AVISTA

RELIABLE ENERGY
AT EVERY TURN

2018 ANNUAL REPORT

Providing safe, reliable energy, supporting the regions we serve, innovating for the future, and upholding strong relationships with our stakeholders is at Avista's core. It's who we are regardless of the opportunities or challenges that come our way. We uphold these values by investing in education and technology advancement in the communities we serve, delivering reliable energy to customers every day, and remaining dedicated to the best interests of our local and regional partnerships.

TO OUR SHAREHOLDERS

This year was an historic year—one of collaboration and transformation that proved Avista's spirit, tenacity and focus.

Our dedicated team, together with Hydro One, worked diligently to formalize our partnership and secure regulatory approval of the proposed merger. Throughout the process, the outcomes of our efforts were remarkable: Collaboration across five states, with multiple, diverse parties, to understand and best meet the needs of all stakeholders, and consensus building that resulted in multi and all party settlement agreements that included outstanding stakeholder commitments and protections unprecedented in the industry.

Even with all of this, the merger faced challenges unforeseen when we entered into our partnership with Hydro One. Despite our firm belief that this transaction was in the best interest of all our stakeholders, these challenges and concerns ultimately led to regulators in Washington and Idaho not approving the transaction. After careful consideration and analysis of the likelihood of achieving a reversal of those orders, the Boards of Directors of both companies each individually determined that terminating the merger agreement was the best course of action, which was announced on January 23, 2019.

While we are disappointed that the proposed merger was not completed as expected, I'm incredibly proud of what we accomplished with Hydro One. We continue to have the highest regard for the company and its management team, and we wish them well going forward. We appreciate the hard work and dedication of everyone who worked with us on this effort over the past 18 months.

The outcome of the merger does not change our commitment to our customers, and in fact, this process has affirmed who Avista is and the way we approach our business. We are a convener, collaborator and innovator that works toward the best shared outcome for Avista and all of our stakeholders.

While we have been focused on completing the merger, we've stayed steady, yet flexible, in ways that allowed us to continue to deliver reliable energy and exceptional service and meet evolving business and customer needs, challenges and expectations. This looked like:

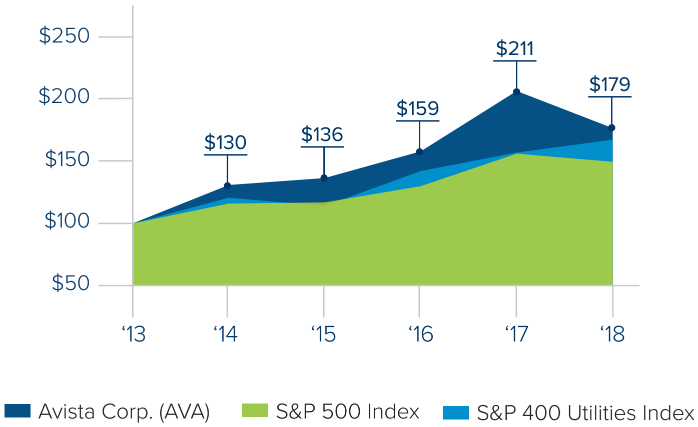
- **Continued capital investment** to maintain and update our utility infrastructure and ensure reliable energy service for our customers.
- **Building the utility of the future** through the first deployment of Advanced Metering Infrastructure and related foundational technology that enables customers to better manage their energy usage.
- **Driving and strengthening economies** through rural vitality initiatives and continued leadership in the Catalyst project and development of an eco-district and innovation hub in Spokane's University District.
- **Cultivating Avista's innovative culture** so that employees continue to think big and identify opportunities to shape our energy future.

We are moving into 2019 and beyond the way Avista does—maintaining our focus on our core business and the future as well as creating tangible value for all of our stakeholders. We look forward to what's ahead, and as we have been for 130 years, we are always here to serve.

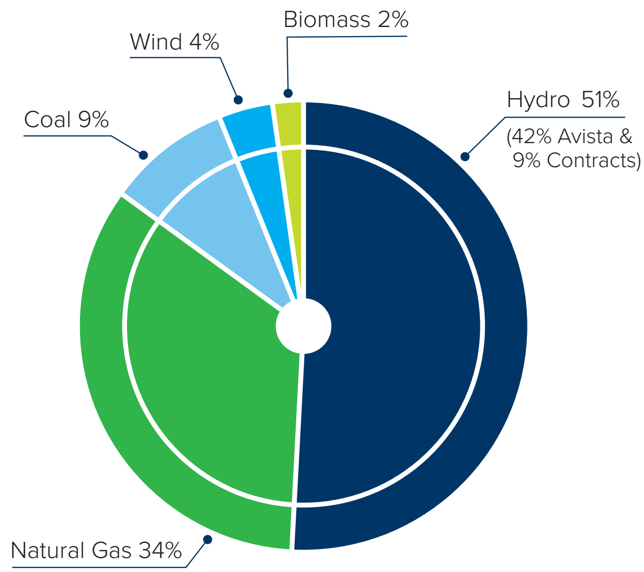
Scott L. Morris
Chairman and Chief Executive Officer

FINANCIAL AND OPERATING HIGHLIGHTS

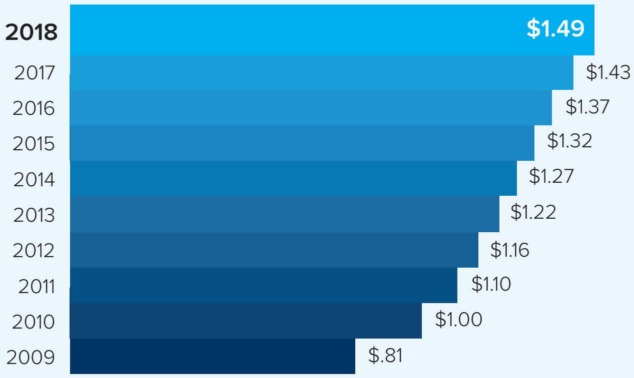
TOTAL SHAREHOLDER RETURN
Assumes $100 was invested in Avista Corp. and each index on Dec. 31, 2013, and that all dividends were reinvested when paid.



ELECTRICITY GENERATION RESOURCE MIX
As of Dec. 31, 2018
Excludes AEL&P

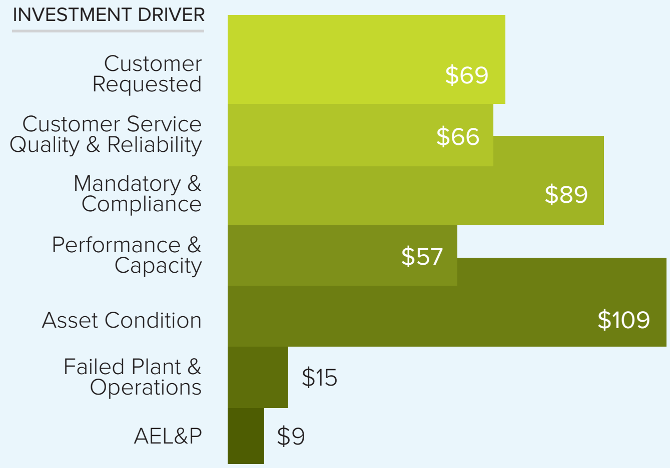


COMMON STOCK DIVIDENDS PAID BY AVISTA CORP.
Annualized Dividend (paid in dollars)



Avista Corp.'s board of directors raised the dividend in each of the last 16 years, reflecting their confidence in the financial strength of the company.

2019 CAPITAL BUDGET
Total capital budget $414 million ($ in millions)



(dollars in thousands except statistics and per share amounts or as otherwise indicated)

	2018	2017	2016
FINANCIAL RESULTS			
Operating revenues	$ 1,396,893	$ 1,445,929	$ 1,442,483
Operating expenses	1,135,780	1,153,750	1,142,622
Income from operations	261,113	292,179	299,861
Net income attributable to Avista Corp. shareholders	136,429	115,916	137,228
Total earnings per common share attributable to Avista Corp. shareholders—diluted	2.07	1.79	2.15
Dividends paid per common share	1.49	1.43	1.37
Book value per common share	$ 26.99	$ 26.41	$ 25.69
Average common shares outstanding	65,673	64,496	63,508
Return on average Avista Corp. stockholders' equity	7.8%	6.9%	8.6%
Common stock closing price	$ 42.48	$ 51.49	$ 39.99
OPERATING RESULTS			
Avista Utilities			
Retail electric revenues	$ 800,670	$ 811,741	$ 759,781
Retail kWh sales (in millions)	8,573	8,897	8,497
Retail electric customers at year-end	387,518	382,131	377,159
Wholesale electric revenues	$ 84,956	$ 81,512	$ 112,071
Wholesale kWh sales (in millions)	3,632	2,881	2,998
Sales of fuel	$ 62,219	$ 64,925	$ 78,334
Other electric revenues	29,301	31,614	28,492
Decoupling (electric)	4,870	(8,220)	17,349
Deferrals and amortizations for rate refunds to customers	(11,477)	(1,182)	932
Retail natural gas revenues	$ 288,434	$ 330,073	$ 293,780
Wholesale natural gas revenues	137,070	142,722	153,446
Transportation and other natural gas revenues	15,927	15,620	14,126
Decoupling (natural gas)	(3,962)	(11,374)	12,309
Deferrals and amortizations for rate refunds to customers	(6,764)	(2,392)	(2,767)
Total therms delivered (in thousands)	1,025,329	1,099,141	1,173,257
Retail natural gas customers at year-end	354,799	347,160	340,131
Net income attributable to Avista Corp. shareholders	$ 134,874	$ 114,716	$ 132,490
Alaska Electric Light and Power Company			
Revenues	$ 43,599	$ 53,027	$ 46,276
Retail kWh sales (in millions)	391	414	393
Retail electric customers at year-end	17,085	16,951	16,798
Net income attributable to Avista Corp. shareholders	8,292	9,054	7,968
Other			
Revenues	$ 27,328	$ 22,543	$ 23,569
Net income (loss) attributable to Avista Corp. shareholders	(6,737)	(7,854)	(3,230)
FINANCIAL CONDITION			
Total assets	$ 5,782,576	$ 5,514,732	$ 5,309,755
Long-term debt and capital leases (including current portion)	1,863,174	1,769,237	1,682,004
Long-term debt to affiliated trusts	51,547	51,547	51,547
Total Avista Corp. stockholders' equity	$ 1,773,220	$ 1,729,828	$ 1,648,727

BOARD OF DIRECTORS

ERIK J. ANDERSON, 60
CEO, Westriver Group
Kirkland, Washington
Director since 2000

KRISTIANNE BLAKE, 65
President, Kristianne Gates Blake, P.S.
Spokane, Washington
Director since 2000

DONALD C. BURKE, 58
Donald C. Burke, CPA
Langhorne, Pennsylvania
Director since 2011

REBECCA A. KLEIN, 53
Principal, Klein Energy, LLC
Austin, Texas
Director since 2010

SCOTT H. MAW, 51
Seattle, Washington
Director since 2016

SCOTT L. MORRIS, 61
Chairman of the Board & CEO, Avista Corp.
Spokane, Washington
Director since 2007

MARC F. RACICOT, 70
Bigfork, Montana
Director since 2009

HEIDI B. STANLEY, 62
Co-owner & Chair, Empire Bolt & Screw Inc.
Spokane, Washington
Director since 2006

R. JOHN TAYLOR, 69
Chairman & CEO, Green Leaf Alliance
Lewiston, Idaho
Director since 1985

DENNIS P. VERMILLION, 57
President, Avista Corp.
Spokane, Washington
Director since 2018

JANET D. WIDMANN, 52
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, 61
Chairman of the Board & CEO

DENNIS P. VERMILLION, 57
President, Board Member

MARK T. THIES, 55
Senior Vice President, CFO & Treasurer

MARIAN M. DURKIN, 65
Senior Vice President, General Counsel, Corporate Secretary & Chief Compliance Officer

KAREN S. FELTES, 63
Senior Vice President & Chief HR Officer

JASON R. THACKSTON, 49
Senior Vice President, Energy Resources & Environmental Compliance Officer

KEVIN J. CHRISTIE, 51
Vice President, External Affairs & Chief Customer Officer

BRYAN A. COX, 49
Vice President, Safety & HR Shared Services

JAMES M. KENSOK, 60
Vice President, CIO & Chief Security Officer

RYAN L. KRASSELT, 49
Vice President, Controller & Principal Accounting Officer

DAVID J. MEYER, 65
Vice President & Chief Counsel for Regulatory & Governmental Affairs

HEATHER L. ROSENTRATER, 41
Vice President, Energy Delivery

EDWARD D. SCHLECT, JR., 58
Vice President & Chief Strategy Officer

CONSTANCE S. HULBERT, 58
President, General Manager, Alaska Electric Light & Power Co.

Ages are as of the proxy date — March 29, 2019

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, 2018** 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 every Interactive Data File required to be submitted 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 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company," and "emerging growth 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	☐		

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 $3,459,103,329 based on the last reported sale price thereof on the consolidated tape on June 30, 2018.

As of January 31, 2019, 65,716,069 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 9, 2019. Prior to such filing, the Proxy Statement filed in connection with the annual meeting of shareholders held on May 10, 2018.	Part III, Items 10, 11, 12, 13 and 14

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PART I

PART II

* *not an applicable item in the 2018 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
Colstrip	– The coal-fired Colstrip Generating Plant in southeastern Montana
Coyote Springs 2	– The natural gas-fired combined-cycle Coyote Springs 2 Generating Plant located near Boardman, Oregon
CT	– Combustion turbine
Deadband or ERM deadband	– The first $4.0 million in annual power supply costs above or below the amount included in base retail rates in Washington under the ERM in the state of Washington
Ecology	– The state of Washington's Department of Ecology
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

Acronyms and Terms (continued)

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

Acronym/Term	Meaning
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
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

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

Acronym/Term	Meaning
PUD	– Public Utility District
RCA	– The Regulatory Commission of Alaska
REC	– Renewable energy credit
ROE	– Return on equity
ROR	– Rate of return on rate base
SEC	– U.S. Securities and Exchange Commission
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, which affect both energy demand and electric generating capability, including the impact of precipitation and temperature on hydroelectric resources, the impact of wind patterns on wind-generated power, weather-sensitive customer demand, and similar impacts 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, other capital market conditions and global economic conditions;
- 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, conservation measures and/or increased distributed generation;
- changes in the long-term global climate and the long-term climate within our utilities' service areas, which can affect, among other things, customer demand patterns, the volume and timing of streamflows to our hydroelectric resources, as well as increased risk of severe weather or natural disasters, including wildfires;
- industry and geographic concentrations which may increase our exposure to credit risks due to counterparties, suppliers and customers being similarly affected by changing conditions;

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;
- the loss of regulatory accounting treatment, which could require the write-off of regulatory assets and the loss of regulatory deferral and recovery mechanisms;

Energy Commodity Risk

- volatility and illiquidity in wholesale energy markets, including exchanges, 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 individual counterparties and/or exchanges 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 or lawsuits affecting our ability to utilize or resulting in the obsolescence of our power supply resources;
- explosions, fires, accidents, pipeline ruptures or other incidents that may limit energy supply to our facilities or our surrounding territory, which could result in a shortage of commodities in the market that could increase the cost of replacement commodities from other sources;

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 fuel, 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, cyberattacks 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, cyberattacks 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 containers 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 other disruptions to the supply chain;
- adverse impacts to our Alaska electric utility 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 cost of replacement power (diesel);
- changing river regulation or operations at hydroelectric facilities not owned by us, which could impact our hydroelectric facilities downstream;
- change in the use, availability or abundancy of water resources and/or rights needed for operation of our hydroelectric facilities;

Compliance Risk

- compliance with extensive federal, state and local legislation and regulation applicable to us, 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;

Cyber and Technology Risk

- cyberattacks 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;
- entering into or growth of non-regulated activities may increase earnings volatility;
- termination of the proposed acquisition of the Company by Hydro One could lead to potential legal proceedings;

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 or 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 that are detrimental or beneficial to our overall business;
- policy and/or legislative changes in various regulated areas, including, but not limited to, environmental regulation, healthcare regulations and import/export 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.myavista.com. We make annual, quarterly and current reports available on our website as soon as practicable after electronically filing these reports with the SEC. The SEC maintains a website that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC at www.sec.gov. Information contained on these websites are 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, 2018, we employed 1,766 people in our Pacific Northwest utility operations (Avista Utilities) and 260 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, 2018, 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 $1,773.2 million as of December 31, 2018, of which $46.9 million represented our investment in Avista Capital and $106.6 million represented our investment in AERC.

See "Item 6. Selected Financial Data" and "Note 22 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 2018, Avista Utilities supplied retail electric service to approximately 388,000 customers and retail natural gas service to approximately 355,000 customers across its service territory. Avista Utilities' service territory covers 30,000 square miles with a population of 1.7 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 and northern Idaho and a small number of customers in Montana, most of whom are employees who operate Avista Utilities' Noxon Rapids generating facility.

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 selection from available energy resources to serve our load obligations and the use of these resources to capture 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, fuel and fuel transportation. Such transactions are part of the process of matching available resources with load obligations and hedging a portion of 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 contracts 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 2018 was 1,716 MW, which occurred on August 10, 2018. In 2017, our peak electric native load was 1,681 MW, which occurred during the winter, and in 2016, it was 1,655 MW, which also occurred during the winter.

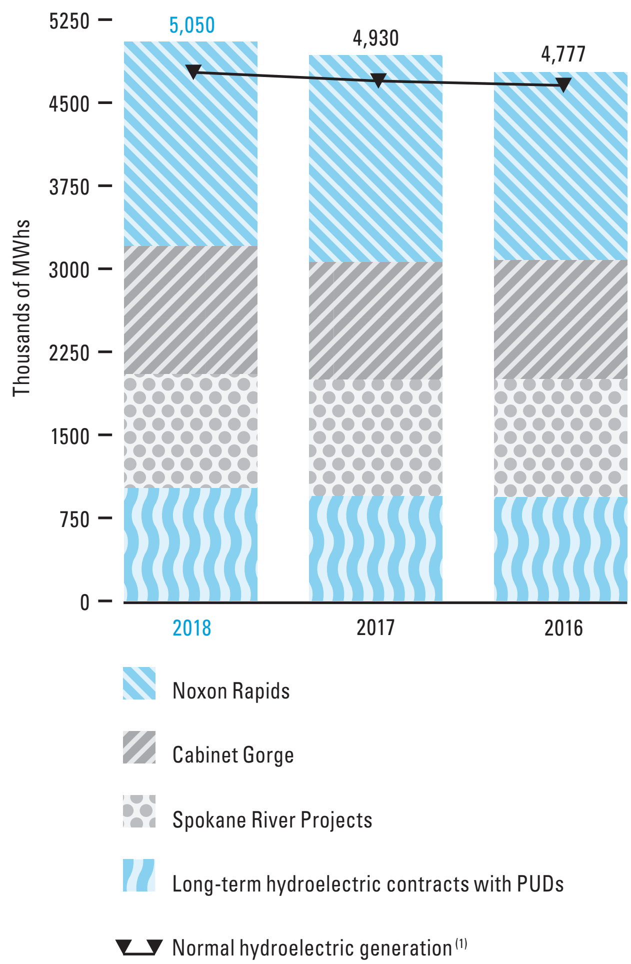
Electric Resources

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. As of December 31, 2018, Avista Utilities' electric generation resource mix (including contracts for power purchases) was approximately 51 percent hydroelectric, 45 percent thermal and 4 percent wind. See "Item 2. Properties" for detailed information on Company-owned 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 2019 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 584 aMW (or 5.1 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, as well as changes in PUD contracts.

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. The current contract for coal supply extends through 2019; however, the coal mine operator is in bankruptcy and has indicated it will reject the current contract in its bankruptcy. The Colstrip co-owners are exploring their options in the bankruptcy court, and have filed an objection to the confirmation plan. 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.

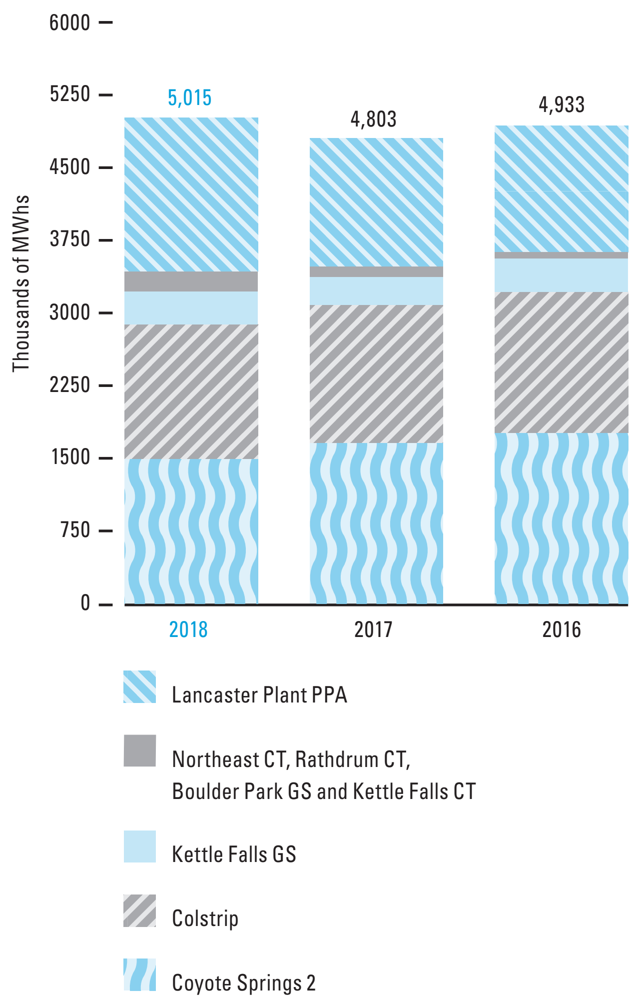
The Northeast CT, Rathdrum CT, Boulder Park GS and Kettle Falls CT generating units are primarily used to meet peaking electric requirements. We also operate these facilities when marginal costs are below prevailing wholesale electric prices. These generating facilities have access to natural gas supplies 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 5 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. The PPA expires in 2042 and 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 327,172 MWhs in 2018, 300,380 MWhs in 2017 and 349,771 MWhs in 2016. 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.

Solar Resources—We have exclusive rights to all the capacity of the Lind Solar Farm, a solar generation project developed, owned and managed by an unrelated third-party and located in Lind, Washington. The PPA expires in 2038 and requires us to acquire all the power and renewable attributes produced by the project at a fixed price per MWh. The project has a nameplate capacity of 28 MW. The facility became operational in the fourth quarter of 2018 and generated 584 MWhs in 2018. 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. In addition to the Lind Solar Farm, we also own a community solar array located in Spokane Valley, Washington with a nameplate capacity of 0.4 MW. The community solar array generated 538 MWhs during 2018.

Other Purchases, Exchanges and Sales—In addition to the resources described above, we purchase and sell power under various long-term contracts, and we also enter into short-term purchases and sales. Further, pursuant to The Public Utility Regulatory Policies Act of 1978, 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" below for annual quantities of purchased power, wholesale power sales and power from exchanges in 2018, 2017 and 2016. 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 20 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.

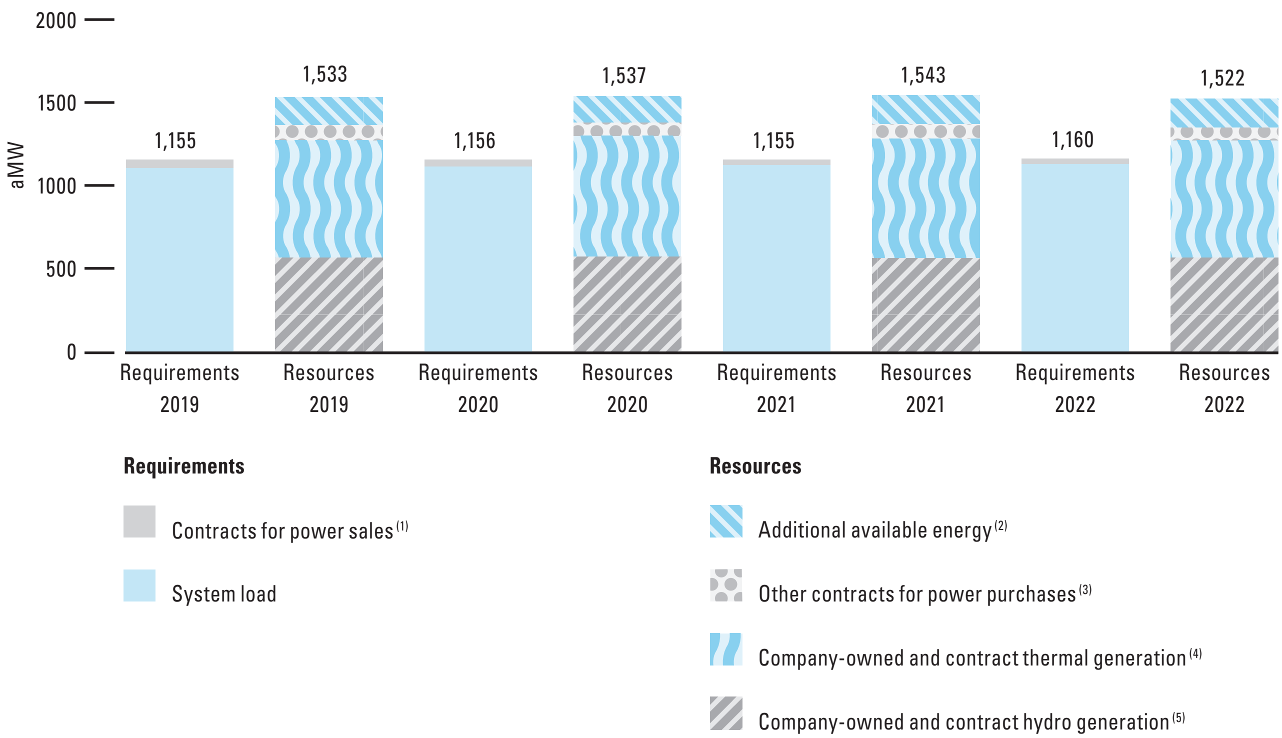
Five of our six hydroelectric projects on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls) are under one 50-year FERC license issued in 2009 and are referred to collectively as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional 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 1,034 aMW in 2018, 1,070 aMW in 2017 and 1,033 aMW in 2016.

The following graph shows our forecast of our average annual energy requirements and our available resources for 2019 through 2022:

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) *Other contracts for power purchases includes power purchase agreements for solar and wind energy.*

(4) *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.*

(5) *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 with 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.

We are required to file an electric IRP every two years. We filed petitions with the WUTC and IPUC in January 2019 to extend the current electric IRP from August 31, 2019 to February 28, 2020 because of the uncertainty created by the current legislative energy proposals in Washington. The WUTC approved our petition in February 2019. We expect the IPUC to approve our petition during the first quarter 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.

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. 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. 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 2018, we filed our 2018 Natural Gas IRP with the WUTC, the IPUC and the OPUC. 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 2018 natural gas IRP include the following expectations and/or assumptions:

- We will need no additional natural gas transportation resources during the 20-year planning horizon in Washington, Idaho, or Oregon.
- Due to expected carbon legislation at the state levels through a cap and trade mechanism (Oregon) or a fee mechanism (Washington), we expect natural gas prices to include a carbon price adder in Oregon and Washington, but not in Idaho.
- North American supplies of natural gas will continue to be abundant led by shale gas development.

- Customer growth in our service territory will increase slightly compared to the 2016 IRP. There will be increasing interest from customers to utilize natural gas for heating due to its abundant supply and consequent low cost.
- We anticipate that any increased demand for natural gas regionally will primarily come from power generation as natural gas is increasingly being used to back up solar and wind technology, and also to replace retired coal plants. There is also potential for increased usage in other markets, such as LNG exports or exports to Mexico.
- Slightly higher customer growth will continue to be offset by lower use per customer and an increased amount of demand side management (DSM). The combination of low priced natural gas in addition to carbon fees or other programs has led to a higher potential for DSM measures as compared to the previous three IRPs.
- 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 foreign markets. This could alter the price of natural gas and/or transportation in U.S. markets, constrain existing pipeline networks, stimulate development of new pipeline resources and change flows of natural gas across North America.

We will monitor these assumptions on an on-going basis and adjust our resource requirements accordingly.

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 2020. Our resource strategy in our 2020 IRP may change from the 2018 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, ongoing capital expenditures and unexpected changes in revenues and expenses 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, 11 and 21 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 21 of the Notes to Consolidated Financial Statements" for information on power cost deferrals and recovery mechanisms in Washington and Idaho.

Purchased Gas Adjustments (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 21 of the Notes to Consolidated Financial Statements" for information on natural gas cost deferrals and recovery mechanisms in Washington, Idaho and Oregon.

Decoupling Mechanisms—Decoupling (also known as FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of its 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" usage, rather than being based on actual usage.

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. 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.

Certain ColumbiaGrid members, including the BPA (ColumbiaGrid's largest funding member), have commenced the process to withdraw from ColumbiaGrid by giving notice of withdrawal from the ColumbiaGrid Planning and Expansion Functional Agreement. On December 18, 2018, Avista Corp. submitted its notice of intent to withdraw from the ColumbiaGrid Planning and Expansion Functional Agreement. Unless rescinded, Avista Corp.'s withdrawal from the Planning and Expansion Functional Agreement will be effective on December 31, 2020. Avista Corp. is currently working with transmission providers from the NTTG and ColumbiaGrid to establish a new regional transmission planning organization that will facilitate regional transmission planning for Avista Corp. and other member organizations.

Regional Energy Markets

The California Independent System Operator (CAISO) operates 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. 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. As market fundamentals and our business needs evolve, we continue to evaluate the drivers (including weighing the advantages and disadvantages) with respect to joining the CAISO EIM. We plan to refine our analyses, including cost estimates, and make a decision in 2019 with regards to participation in the EIM.

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 September 2, 2019. After the CAISO submitted its notice of withdrawal from Peak Reliability, other funding parties, including Avista Corp., also submitted a revocable notice of withdrawal from Peak Reliability. Unless revoked, our withdrawal from Peak Reliability will be effective on December 31, 2019. We have signed an agreement to receive reliability coordination services from the CAISO. We are scheduled to transition to the CAISO for reliability coordination services in November 2019.

Vulnerability to Cyberattack

The energy sector, particularly electric and natural gas utility companies in the United States and abroad, have become the subject of cyberattacks 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—Cyber and Technology Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Enterprise Risk Management—Cyber and Technology Risks" for further information.

Avista Utilities Electric Operating Statistics
Years Ended December 31,

	2018	2017	2016
Electric Operations			
Operating Revenues (Dollars in Thousands):			
Residential	$ 368,753	$ 381,682	$ 339,210
Commercial	314,532	311,593	305,613
Industrial	109,846	110,982	107,296
Public street and highway lighting	7,539	7,484	7,662
Total retail	800,670	811,741	759,781
Wholesale	84,956	81,512	112,071
Sales of fuel	62,219	64,925	78,334
Other	29,301	31,614	28,492
Alternative revenue programs	4,870	(8,220)	17,349
Deferrals and amortizations for rate refunds to customers	(11,477)	(1,182)	932
Total electric operating revenues	$ 970,539	$ 980,390	$ 996,959
Energy Sales (Thousands of MWhs):			
Residential	3,627	3,840	3,528
Commercial	3,156	3,222	3,183
Industrial	1,772	1,815	1,763
Public street and highway lighting	18	20	23
Total retail	8,573	8,897	8,497
Wholesale	3,632	2,881	2,998
Total electric energy sales	12,205	11,778	11,495
Energy Resources (Thousands of MWhs):			
Hydro generation (from Company facilities)	4,029	3,978	3,836
Thermal generation (from Company facilities)	3,424	3,476	3,626
Purchased power	5,349	4,809	4,597
Power exchanges	(109)	(6)	(6)
Total power resources	12,693	12,257	12,053
Energy losses and Company use	(488)	(479)	(558)
Total energy resources (net of losses)	12,205	11,778	11,495
Number of Retail Customers (Average for Period):			
Residential	340,308	334,848	330,699
Commercial	42,618	42,154	41,785
Industrial	1,318	1,328	1,342
Public street and highway lighting	594	569	558
Total electric retail customers	384,838	378,899	374,384
Residential Service Averages:			
Annual use per customer (KWh)	10,658	11,469	10,667
Revenue per KWh (in cents)	10.17	9.94	9.62
Annual revenue per customer	$ 1,083.58	$ 1,139.87	$ 1,025.74
Average Hourly Load (aMW)	1,034	1,070	1,033

Avista Utilities Electric Operating Statistics
Years Ended December 31,

	2018	2017	2016
Electric Operations (continued)			
Retail Native Load at time of system peak (MW):			
Winter	1,555	1,681	1,655
Summer	1,716	1,596	1,587
Cooling Degree Days: (1)			
Spokane, WA			
Actual	517	743	474
Historical average	544	529	545
% of average	95%	140%	87%
Heating Degree Days: (2)			
Spokane, WA			
Actual	6,159	6,783	5,790
Historical average	6,593	6,578	6,680
% of average	93%	103%	87%

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

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

Avista Utilities Natural Gas Operating Statistics
Years Ended December 31,

	2018	2017	2016
Natural Gas Operations			
Operating Revenues (Dollars in Thousands):			
Residential	$ 194,340	$ 220,176	$ 195,275
Commercial	89,341	104,240	92,978
Interruptible	1,886	1,901	2,179
Industrial	2,867	3,756	3,348
Total retail	288,434	330,073	293,780
Wholesale	137,070	142,722	153,446
Transportation	9,103	9,208	8,339
Other	6,824	6,412	5,787
Alternative revenue programs	(3,962)	(11,374)	12,309
Deferrals and amortizations for rate refunds to customers	(6,764)	(2,392)	(2,767)
Total natural gas operating revenues	$ 430,705	$ 474,649	$ 470,894
Therms Delivered (Thousands of Therms):			
Residential	208,344	221,982	186,565
Commercial	124,670	133,343	112,686
Interruptible	5,750	5,465	5,700
Industrial	5,801	6,340	5,234
Total retail	344,565	367,130	310,185
Wholesale	503,913	545,348	684,317
Transportation	176,439	186,222	178,377
Interdepartmental and Company use	412	441	378
Total therms delivered	1,025,329	1,099,141	1,173,257
Number of Retail Customers (Average for Period):			
Residential	314,800	307,375	300,883
Commercial	35,488	35,192	34,868
Interruptible	39	37	37
Industrial	246	251	255
Total natural gas retail customers	350,573	342,855	336,043
Residential Service Averages:			
Annual use per customer (therms)	662	722	620
Revenue per therm (in dollars)	$ 0.93	$ 0.99	$ 1.05
Annual revenue per customer	$ 617.35	$ 716.31	$ 649.01
Heating Degree Days: (1)			
Spokane, WA			
Actual	6,159	6,783	5,790
Historical average	6,593	6,578	6,680
% of average	93%	103%	87%
Medford, OR			
Actual	4,155	4,254	3,637
Historical average	4,297	4,305	4,325
% of average	97%	99%	84%

(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).

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, 2018. 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).

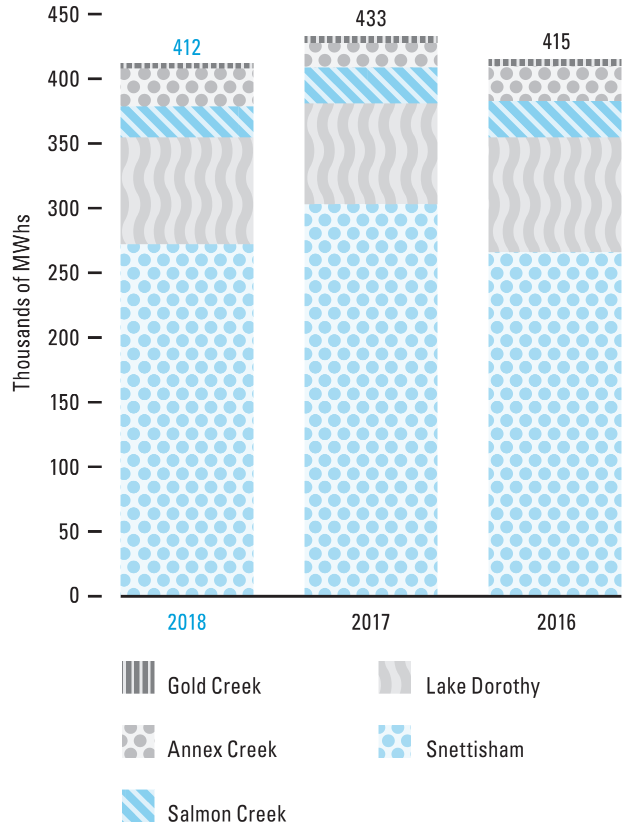
The Snettisham hydroelectric project is owned by the Alaska Industrial Development and Export Authority (AIDEA), a public corporation of the State of Alaska. AIDEA issued revenue bonds in 1998 (which were refinanced in 2015) to finance its acquisition of the project. These bonds were outstanding in the amount of $57.2 million at December 31, 2018 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, 2018, the capital lease obligation was $57.2 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, 2018, 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



Normal hydroelectric generation is defined as the energy output of the plant during a year with average inflows to the reservoir. Normal annual hydroelectric generation for AEL&P is approximately 430,000 MWhs.

As of December 31, 2018, 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 with respect to permits and licenses necessary to operate certain of its hydroelectric facilities. One of these licenses (for the Salmon Creek and Annex Creek hydroelectric projects) was renewed for 40 years, effective September 1, 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,

	2018	2017	2016
Electric Operations			
Operating Revenues (Dollars in Thousands):			
Residential	$ 18,506	$ 20,504	$ 18,207
Commercial and government	25,989	31,726	27,322
Public street and highway lighting	263	279	266
Total retail	44,758	52,509	45,795
Other	(1,159)	518	481
Total electric operating revenues	$ 43,599	$ 53,027	$ 46,276
Energy Sales (Thousands of MWhs):			
Residential	149	151	139
Commercial and government	241	262	253
Public street and highway lighting	1	1	1
Total electric energy sales	391	414	393
Number of Retail Customers (Average for Period):			
Residential	14,677	14,575	14,448
Commercial and government	2,234	2,210	2,181
Public street and highway lighting	224	217	211
Total electric retail customers	17,135	17,002	16,840
Residential Service Averages:			
Annual use per customer (KWh)	10,152	10,360	9,621
Revenue per KWh (in cents)	12.42	13.58	13.10
Annual revenue per customer	$ 1,260.88	$ 1,406.79	$ 1,260.17
Heating Degree Days: (1)			
Juneau, AK			
Actual	7,973	8,515	7,301
Historical average	8,351	8,351	8,351
% of average	95%	102%	87%

(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, 2018 and 2017 (dollars in thousands):

Entity and Asset Type		2018		2017
Avista Capital				
Salix, Inc.—wholly-owned subsidiary	$	4,209	$	4,392
Equity investments		1,568		2,561
Other assets		2,937		2,826
Avista Development				
Equity investments		27,689		19,573
Real estate		18,573		17,102
Notes receivable and other assets		9,296		6,385
METALfx—wholly-owned subsidiary		13,497		11,599
Alaska companies (AERC and AJT Mining)		9,281		8,803
Total	$	87,050	$	73,241

Avista Capital

- Salix, Inc. is a wholly-owned subsidiary of Avista Capital that explores markets that could be served with LNG, primarily in western North America.
- 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 predictive data science company and an investment in a joint venture focused on local real estate development and economic growth.
- 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 predictive data science 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 $1.0 million as of December 31, 2018 and $5.6 million as of December 31, 2017.

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. 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. 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.

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 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, 2018, we had a net interest rate swap derivative liability of $2.7 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, 2018. 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.

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. During 2018, Moody's downgraded our credit rating due in part to less predictability with regulatory outcomes in Washington as a contributing factor for the downgrade. Further actions by the credit rating agencies 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."

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. If market prices decrease compared to the prices we have locked in with our energy commodity derivatives, this will result in a liability related to these derivatives, which can be significant. As of December 31, 2018, we had a gross energy commodity derivative liability of $94.6 million (exclusive of amounts posted as collateral and derivative assets eligible for net balance sheet presentation). As a result of price fluctuations, we may be required to post significant amounts of cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments. As of December 31, 2018, we had $78.0 million posted as cash collateral and $6.5 million of letters of credit posted as collateral.

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 or legislation. 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,
- property damage or injuries to third parties caused by our generation, transmission and distribution systems,
- wildfires caused by our transmission and distribution systems, which could result in extensive property damage or injuries to third parties,
- 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. If insurance or indemnification agreements are unable to adequately protect us or reimburse us for out-of-pocket costs, it could have a material adverse effect on our results of operations, financial condition and cash flows.

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 to AEL&P could result from an extended outage of its hydroelectric generating resources or its inability to deliver energy, due to its lack of interconnectivity to any other electrical grids and the 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, administrative rules or Executive Orders 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 20 of the Notes to Consolidated Financial Statements" for further details of these matters.

Cyber and Technology Risk Factors

Cyberattacks, 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.

Cyberattacks, terrorism or other malicious acts could damage, destroy or disrupt these systems for an extended period of time. The energy sector, particularly electric and natural gas utility companies have become the subject of cyberattacks with increased frequency. Our administrative and operating networks are targeted by hackers on a regular basis. Additionally, the facilities and systems of clients, suppliers and third party service providers could be vulnerable to the same cyber or terrorism risks as our facilities and systems and such third party systems may be interconnected to our systems both physically and technologically. Therefore, an event caused by cyberattacks or other malicious act at an interconnected third party could impact our business and facilities similarly. 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 cyberattacks 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 our physical electric and natural gas facilities, as well as technology systems or at an interconnected third party, which could result in disruption to our systems.

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

We are in the process of replacing all of our electric meter infrastructure in Washington State with two-way communication advanced metering infrastructure (AMI). 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.

Legal proceedings related to the terminated acquisition by Hydro One.

In connection with the proposed acquisition, three lawsuits were filed in the United States District Court for the Eastern District of Washington and one lawsuit was filed in the Superior Court for the State of Washington in and for Spokane County. The three federal lawsuits were voluntarily dismissed by the plaintiffs.

The Washington State complaint generally alleged 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 was stayed by the court until the closing of the transaction at which time the plaintiff would have the option to file an amended complaint within 30 days of such closing. If the amended complaint was not filed within the 30 days the suit would be dismissed. Since the transaction will not close, the status of this lawsuit is unknown.

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.

In addition to the lawsuits already filed, there could be additional legal proceedings associated with the termination of the proposed acquisition.

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.

Import tariffs could lead to increased prices on raw materials that are critical to our business.

Import tariffs and/or other mandates imposed by the current presidential administration could potentially lead to a trade war with other foreign governments, and could significantly increase the prices on raw materials that are critical to our business, such as steel poles or wires. In addition, tariff increases may have a similar impact to our other suppliers and certain other customers, which could increase the negative impact on our operating results or future cash flows, as well as impact customer rates.

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	30.3
Nine Mile (Spokane)	4	37.6	34.0
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	11.9
Montana:			
Noxon Rapids (Clark Fork)	5	487.8	562.4
Total Hydroelectric		940.4	1,024.8
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	1,858.1

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

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2018.

(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 1,570 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, 2,100 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, 2018.

(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 20 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, 2019, there were 7,416 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 preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements (see "Item 7. Management's Discussion and Analysis—Capital Resources" for compliance with these covenants),
- the hydroelectric licensing requirements of section 10(d) of the FPA (see "Note 1 of Notes to Consolidated Financial Statements"), and
- certain requirements under the OPUC approval of the AERC acquisition 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.

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

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

ITEM 6.

Selected Financial Data

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

	2018	2017	2016	2015	2014
Operating Revenues:					
Avista Utilities	$ 1,325,966	$ 1,370,359	$ 1,372,638	$ 1,411,863	$ 1,413,499
AEL&P	43,599	53,027	46,276	44,778	21,644
Other	27,328	22,543	23,569	28,685	39,219
Intersegment eliminations	—	—	—	(550)	(1,800)
Total	$ 1,396,893	$ 1,445,929	$ 1,442,483	$ 1,484,776	$ 1,472,562
Income (Loss) from Operations (pre-tax):					
Avista Utilities	$ 248,000	$ 278,079	$ 287,128	$ 249,586	$ 243,535
AEL&P	14,665	17,947	15,434	14,072	6,221
Other	(1,552)	(3,847)	(2,701)	(2,086)	6,391
Total	$ 261,113	$ 292,179	$ 299,861	$ 261,572	$ 256,147
Net income from continuing operations	$ 136,598	$ 115,932	$ 137,316	$ 118,170	$ 119,866
Net income from discontinued operations	—	—	—	5,147	72,411
Net income	136,598	115,932	137,316	123,317	192,277
Net income attributable to noncontrolling interests	(169)	(16)	(88)	(90)	(236)
Net income attributable to Avista Corp. shareholders	$ 136,429	$ 115,916	$ 137,228	$ 123,227	$ 192,041
Net Income (Loss) attributable to Avista Corporation shareholders:					
Avista Utilities	$ 134,874	$ 114,716	$ 132,490	$ 113,360	$ 113,263
AEL&P	8,292	9,054	7,968	6,641	3,152
Discontinued operations	—	—	—	5,147	72,390
Other	(6,737)	(7,854)	(3,230)	(1,921)	3,236
Net income attributable to Avista Corp. shareholders	$ 136,429	$ 115,916	$ 137,228	$ 123,227	$ 192,041
Average common shares outstanding—basic	65,673	64,496	63,508	62,301	61,632
Average common shares outstanding—diluted	65,946	64,806	63,920	62,708	61,887
Common shares outstanding at year-end	65,688	65,494	64,188	62,313	62,243
Earnings per common share attributable to Avista Corp. shareholders—basic:					
Earnings per common share from continuing operations	$ 2.08	$ 1.80	$ 2.16	$ 1.90	$ 1.94
Earnings per common share from discontinued operations	—	—	—	0.08	1.18
Total earnings per common share attributable to Avista Corp. shareholders—basic	$ 2.08	$ 1.80	$ 2.16	$ 1.98	$ 3.12
Earnings per common share attributable to Avista Corp. shareholders—diluted:					
Earnings per common share from continuing operations	$ 2.07	$ 1.79	$ 2.15	$ 1.89	$ 1.93
Earnings per common share from discontinued operations	—	—	—	0.08	1.17
Total earnings per common share attributable to Avista Corp. shareholders—diluted	$ 2.07	$ 1.79	$ 2.15	$ 1.97	$ 3.10
Dividends declared per common share	$ 1.49	$ 1.43	$ 1.37	$ 1.32	$ 1.27
Book value per common share	$ 26.99	$ 26.41	$ 25.69	$ 24.53	$ 23.84

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

	2018	2017	2016	2015	2014
Total Assets at Year-End:					
Avista Utilities	$ 5,458,104	$ 5,177,878	$ 4,975,555	$ 4,601,708	$ 4,357,760
AEL&P	272,950	278,688	273,770	265,735	263,070
Other	87,050	73,241	60,430	39,206	80,141
Intersegment eliminations	(35,528)	(15,075)	—	—	—
Total	$ 5,782,576	$ 5,514,732	$ 5,309,755	$ 4,906,649	$ 4,700,971
Long-Term Debt and Capital Leases (including current portion)	$ 1,863,174	$ 1,769,237	$ 1,682,004	$ 1,573,278	$ 1,487,126
Nonrecourse Long-Term Debt of Spokane Energy					
(including current portion)	$ —	$ —	$ —	$ —	$ 1,431
Long-Term Debt to Affiliated Trusts	$ 51,547	$ 51,547	$ 51,547	$ 51,547	$ 51,547
Total Avista Corp. Shareholders' Equity	$ 1,773,220	$ 1,729,828	$ 1,648,727	$ 1,528,626	$ 1,483,671

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

Business Segments

As of December 31, 2018, 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):

	2018	2017	2016
Avista Utilities	$ 134,874	$ 114,716	$ 132,490
AEL&P	8,292	9,054	7,968
Other	(6,737)	(7,854)	(3,230)
Net income attributable to Avista Corporation shareholders	$ 136,429	$ 115,916	$ 137,228

Executive Level Summary

Overall Results

Net income attributable to Avista Corp. shareholders was $136.4 million for 2018, an increase from $115.9 million for 2017.

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

Avista Utilities' earnings increased for 2018 primarily due to a decrease in acquisition costs relating to the terminated acquisition by Hydro One and the positive impact of general rate increases and customer growth. These factors were partially offset by increased distribution and generation operating and maintenance costs, outside service costs (other operating expenses), depreciation and amortization, and interest expense.

AEL&P earnings decreased for 2018, primarily due to an increase in depreciation and amortization and other miscellaneous expenses as well as a decrease in sales volumes to residential and commercial customers primarily during the fourth quarter of 2018.

Losses at our other businesses decreased during 2018 as 2017 included a one-time tax expense in the fourth quarter from revaluing deferred taxes to the new tax rate of 21 percent as a result of federal income tax law changes. There was also a gain in 2018 from one of our equity investments. These were partially offset by increased expenses associated with a renovation project in 2018, impairment losses and an increase in losses on certain of our subsidiary 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).

General Rate Cases and Regulatory Lag

Due in part to the regulatory proceedings for the now terminated acquisition of the Company by Hydro One (see below), we elected not to file any general rate cases during 2018 to allow the commissions to focus on the merger proceedings. While we received a base rate increase effective January 1, 2019 in Idaho, which was related to a rate plan approved by the IPUC in 2017, we have not received base rate relief in Oregon since November 1, 2017, and have not received base rate relief in Washington since May 1, 2018. During 2017 and 2018, we continued to invest in our utility infrastructure to maintain and enhance our system; however, only limited portions of these costs are reflected in our current rates to customers. As such, we expect to experience regulatory lag during the period 2019 through 2021 due to the delay in general rate case filings and our continued investment in utility infrastructure. We plan to file general rate cases in Washington, Idaho and Oregon during the first half of 2019 with requested effective dates in early 2020 to begin remedying the regulatory lag. Going forward, we will continue to strive to reduce the regulatory timing lag and more closely align our earned returns with those authorized by 2022. This will require adequate and timely rate relief in our jurisdictions.

Termination of the Proposed Acquisition by Hydro One

On July 19, 2017, Avista Corp. entered into a Merger Agreement that provided 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.

On January 23, 2019, Avista Corp., Hydro One and certain subsidiaries thereof, entered into a termination agreement (Termination Agreement) indicating their mutual agreement to terminate the Merger Agreement, effective immediately. Pursuant to the terms of the Merger Agreement and the Termination Agreement, Hydro One paid Avista Corp. a $103 million termination fee on January 24, 2019. The termination fee will be used for reimbursing our transaction costs incurred from 2017 to 2019. These costs, including income taxes, total approximately $51 million. The balance of the termination fee will be used for general corporate purposes and reduces our need for external financing. For further information, see "Notes 20 and 24 of the Notes to Consolidated Financial Statements."

Federal Income Tax Law Changes

On December 22, 2017, the TCJA was signed into law, with most provisions of the new law effective on January 1, 2018. As a result of the TCJA and its reduction of the corporate income tax rate from 35 percent to 21 percent (among many other changes in the law), we recorded a regulatory liability associated with the revaluing of our deferred income tax assets and liabilities to the new corporate tax rate. The regulatory liability for plant-related excess deferred income taxes will be returned to customers through their future rates. The regulatory liability for non-plant excess deferred taxes will be returned to customers as prescribed by proposed settlement agreements in Washington, Idaho and Oregon discussed at "Regulatory Matters." The return of excess deferred income taxes does not impact our net income.

Because most of the provisions of the TCJA were effective as of January 1, 2018 but customers' rates included a 35 percent corporate tax rate built in from prior general rate cases, we began accruing for a refund to customers for the change in federal income tax expense beginning January 1, 2018 forward. For Washington and Idaho, this accrual was recorded until all benefits prior to a permanent rate change were properly captured through the deferral process. Refunds have begun for Washington and Idaho customers through tariffs or other regulatory mechanisms or proceedings. For Oregon, we will continue to defer these benefits until reflected in a future regulatory proceeding as approved by the OPUC.

The primary impact to us from the TCJA is the loss of the bonus depreciation tax deduction, which results in less depreciation as a current tax deduction, which increases our taxable income and results in us having to pay taxes earlier than we had projected under the old tax laws. This negative impact to cash flows has impacted certain financial metrics used by credit rating agencies to evaluate the Company. The negative impact to our financial metrics contributed to Moody's downgrading our credit rating in 2018. Moody's also cited uncertainty with respect to regulatory outcomes in Washington as a contributing factor for the downgrade. Any further actions by credit ratings 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 "Credit Ratings" for additional discussion.

See "Regulatory Matters" and "Note 11 of the Notes to Consolidated Financial Statements" 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 and Other Proceedings

2015 General Rate Cases

In January 2016 we received an order which was reaffirmed by the WUTC in February 2016 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 an ROR of 7.29 percent, with a common equity ratio of 48.5 percent and a 9.5 percent ROE.

In March 2016, the Public Counsel Unit of the Washington State Office of the Attorney General filed in Thurston County Superior Court a Petition for Judicial Review of the WUTC's orders that concluded our 2015 electric and natural gas general rate cases. In April 2016, this matter was certified for review directly by the Court of Appeals, an intermediate appellate court in the State of Washington.

On August 7, 2018, the Court of Appeals issued an Opinion which concluded that the WUTC's use of an attrition allowance to calculate Avista Corp.'s rate base violated Washington law. The Court struck all portions of the attrition allowance attributable to Avista Corp.'s rate base and reversed and remanded the case for the WUTC to recalculate Avista Corp.'s rates without including an attrition allowance in the calculation of rate base.

The total attrition allowance approved by the WUTC was $35.2 million, with $28.3 million related to electric and $6.9 million related to natural gas. The Company cannot predict the outcome of this matter at this time and cannot estimate how much, if any, of the attrition allowance may be removed from the general rate cases. The regulatory process to address this matter has not yet been established by the WUTC. See "Note 20 of the Notes to Consolidated Financial Statements" for further discussion of this matter.

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 did not appeal the WUTC's decision to the courts and instead focused on new general rate cases.

2017 General Rate Cases

On April 26, 2018, the WUTC issued a final order in our electric and natural gas general rate cases that were originally filed on May 26, 2017. In the order, the WUTC approved new electric rates, effective on May 1, 2018, that increased base rates by 2.2 percent (designed to increase electric revenues by $10.8 million). The net increase in electric base rates was made up of an increase in our base revenue requirement of $23.2 million, an increase of $14.5 million in power supply costs and a decrease of $26.9 million for the impacts of the TCJA, which reflects the federal income tax rate change from 35 percent to 21 percent and the amortization of the regulatory liability for plant excess deferred income taxes that was recorded as of December 31, 2017.

While the WUTC authorized an increase in the ERM baseline to reflect increased power supply costs, it directed the parties to examine the functionality and rationale of the Company's power cost modeling and adjust the baseline only in extraordinary circumstances if necessary to more closely match the baseline to actual conditions.

For natural gas, the WUTC approved new natural gas base rates, effective on May 1, 2018, that decreased base rates by 2.4 percent (designed to decrease natural gas revenues by $2.1 million). The net decrease in natural gas base rates was made up of an increase in base revenues of $3.4 million that was offset by a decrease of $5.5 million for the impacts from the TCJA, which reflects the federal income tax rate change and the amortization of the regulatory liability for plant-related excess deferred income taxes that was recorded as of December 31, 2017.

In addition to the above, the WUTC also ordered, effective June 1, 2018, a one-year temporary reduction of $7.9 million in our revenue requirements for electric and $3.2 million for natural gas, reflecting reductions for the return of tax benefits associated with the non-plant excess deferred income taxes and the customer refund liability that was established in 2018 related to the change in federal income tax expense for the period January 1, 2018 to April 30, 2018.

The new rates are based on a ROR of 7.50 percent with a common equity ratio of 48.5 percent and a 9.5 percent ROE.

In our original filings, we requested three-year rate plans for electric and natural gas; however, in the final order the WUTC only provided for new rates effective on May 1, 2018.

In testimony filed in our 2017 general rate case, the WUTC Staff recommended the exclusion of our 2016 settlement costs of interest rate swaps from the cost of capital calculation. In the final order, the WUTC disagreed with WUTC Staff and did not disallow the settlement costs of our interest rate swaps. However, the WUTC did recommend that we make changes to our interest rate risk hedging policy to be more risk responsive. We are evaluating and making changes to our policy to meet the WUTC recommendations.

TCJA Proceedings

In February 2019, we filed an all-party settlement agreement with the WUTC related to the electric tax benefits that were set aside for Colstrip in the 2017 general rate case order. In the settlement agreement, the parties agreed to utilize $10.9 million of the electric tax benefits to offset costs associated with accelerating the depreciation of Colstrip Units 3 & 4, to reflect a remaining useful life of those units through December 31, 2027. The settlement agreement is subject to WUTC approval.

Although the parties to the settlement agreement have agreed to the acceleration of depreciation of Colstrip Units 3 & 4, the settlement does not reflect any agreement with respect to the ultimate closure of Colstrip Units 3 & 4, since that decision would have to be made in conjunction with the other owners of Colstrip.

2019 General Rate Cases

We expect to file electric and natural gas general rate cases with the WUTC in the first half of 2019.

Idaho General Rate Cases and Other Proceedings

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 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.

TCJA Proceedings

On May 31, 2018, the IPUC approved the all-party settlement agreement related to the income tax benefits associated with the TCJA. Effective June 1, 2018, through separate tariff schedules, until such time as these changes can be reflected in base rates within the next general rate case, current customer rates were reduced to reflect the reduction of the federal income tax rate to 21 percent, and the amortization of the regulatory liability for plant-related excess deferred income taxes. This reduction reduces annual electric rates by $13.7 million (or 5.3 percent reduction to base rates) and natural gas rates by $2.6 million (or 6.1 percent reduction to base rates).

In February 2019, we filed an all-party settlement agreement with the IPUC related to the electric tax benefits that were set aside for Colstrip in the 2017 general rate case order. In the settlement agreement, the parties agreed to utilize approximately $6.4 million of the electric tax benefits to offset costs associated with accelerating the depreciation of Colstrip Units 3 & 4, to reflect a remaining useful life of those units through December 31, 2027. The remaining tax benefits of approximately $5.8 million will be returned to customers through a temporary rate reduction over a period of one year beginning on April 1, 2019. The tax benefits being utilized are related to non-plant excess deferred income taxes, and the customer refund liability that was established in 2018 related to the change in federal income tax expense for the period January 1, 2018 to May 31, 2018. The settlement agreement is subject to IPUC approval.

2019 General Rate Cases

We expect to file electric and natural gas general rate cases with the IPUC in the second quarter of 2019.

Oregon General Rate Cases and Other Proceedings

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.

TCJA Proceedings

In February 2019, the OPUC approved the deferral amount of $3.8 million related to 2018 income tax benefits associated with the TCJA. The 2018 deferred benefits are expected to be returned to customers through a temporary rate reduction over a period of one year beginning March 1, 2019. We requested to continue the deferral of the TCJA benefits during 2019 for later return to customers, until such time as these changes can be reflected in base rates.

2019 General Rate Case

We expect to file a natural gas general rate case with the OPUC in the first quarter of 2019.

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. As of December 31, 2018, the estimated future undepreciated value for the existing electric meters is $20.6 million. In September 2017, the WUTC also approved our request to defer the undepreciated net book value of existing natural gas encoder receiver transmitters (ERT) (consistent with the accounting treatment we obtained on our existing electric meters) that will be retired as part of the AMI project. As of December 31, 2018, the estimated future undepreciated value for the existing natural gas ERTs is $3.7 million. Replacement of the electric meters and natural gas ERTs began during the second half of 2018.

In September 2017, the WUTC approved a Petition to defer the depreciation expense associated with the AMI project, 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.

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 2017 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.

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

TCJA Proceedings

The RCA approved a settlement agreement between AEL&P and the Attorney General filed on June 15, 2018 (Order 3). Per Order 3, effective August 1, 2018, AEL&P reduced firm customer base rates by 6.7 percent ($2.4 million annually), to reflect income tax expense reductions associated with the TCJA. The RCA also approved AEL&P's proposal to refund to customers a one-time credit equal to the 6.7 percent rate reduction for bills between January 1 and July 31, 2018. AEL&P completed all one-time credits during the third quarter of 2018. The impact of the TCJA on AEL&P's deferred income taxes will be addressed in AEL&P's next general rate case, due to be filed by August 30, 2021.

Avista Utilities

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to Avista Utilities' customers with no change in utility 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 $40.7 million as of December 31, 2018 and a liability of $37.5 million as of December 31, 2017. These deferred natural gas costs balances represent amounts due to customers.

The following PGAs went into effect in our various jurisdictions during 2016 through 2018:

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	November 1, 2016	(8.0)%
	November 1, 2017	(5.2)%
	January 26, 2018 (1)	(7.1)%
	November 1, 2018	(0.1)%
Idaho	November 1, 2016	(7.8)%
	November 1, 2017	(2.7)%
	January 26, 2018 (1)	(7.4)%
	November 1, 2018	(1.0)%
Oregon	November 1, 2016	(6.0)%
	November 1, 2017	(2.1)%
	January 26, 2018 (1)	(3.5)%
	November 1, 2018	(2.9)%

(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 $34.4 million as of December 31, 2018 and a liability $23.7 million as of December 31, 2017. These deferred power cost balances represent amounts due to customers. Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million in the rebate or surcharge direction, we must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from 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. The 2019 filing will also contain a proposed rate adjustment or refund, effective July 1, 2019, due to the cumulative rebate balance exceeding $30 million.

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 $7.6 million as of December 31, 2018 and a liability of $6.1 million as of December 31, 2017. 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. In February 2019, the WUTC approved an all-party agreement that extends the life of the mechanisms through the end of our next general rate case, or April 1, 2020, whichever comes first. In that general rate case we will seek to either make permanent or extend the mechanisms for an additional multi-year term. 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.

Idaho FCA Mechanism

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. During the first quarter of 2018, the FCA in Idaho was extended for a one-year term through December 31, 2019. We expect to seek an extension of the FCAs in our next general rate case, expected in the second quarter of 2019.

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.

Cumulative Decoupling and Earnings Sharing Balances

Total net cumulative decoupling deferrals among all jurisdictions were regulatory assets of $13.9 million as of December 31, 2018 and $16.5 million as of December 31, 2017. These decoupling assets represent amounts due from customers. Total net earnings sharing balances among all jurisdictions were regulatory liabilities of $1.5 million as of December 31, 2018 and $5.8 million as of December 31, 2017. These earnings sharing liabilities represent amounts due to customers.

See "Results of Operations—Avista Utilities" for further discussion of the amounts recorded to operating revenues in 2016 through 2018 related to the decoupling and earnings sharing mechanisms.

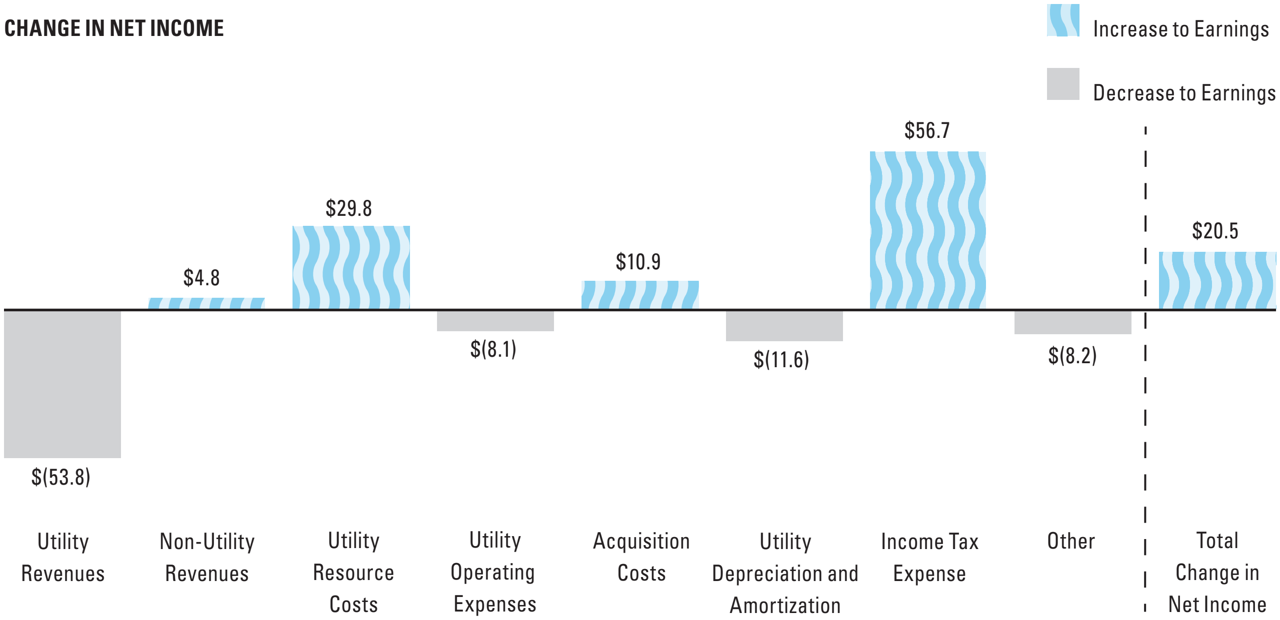
Results of Operations—Overall

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 and the other businesses) that follow this section.

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

2018 Compared to 2017

The following graph shows the total change in net income attributable to Avista Corp. shareholders for 2017 to 2018, as well as the various factors that caused such change (dollars in millions):



Utility revenues decreased at both Avista Utilities and AEL&P. Avista Utilities' revenues decreased primarily due to lower retail electric and natural gas sales volumes (due to warmer weather in the heating season and cooler weather in the cooling season) and accruals for refunds to customers and decreases to retail rates related to federal income tax law changes. As our customers' rates had the 35 percent corporate tax rate built in from prior general rate cases through May 1, 2018 in Washington and June 1, 2018 in Idaho, we deferred the impact of the change beginning January 1, 2018. Effective May 1, 2018 in Washington and June 1, 2018 in Idaho, base rates reflect the lower 21 percent corporate tax. Base rates in Oregon continue to have the 35 percent corporate tax rate built in and we are deferring the impact. There was no impact on our net income, as there was a corresponding decrease in income tax expense. Avista Utilities' decrease in revenues was partially offset by an increase in revenue from general rate increases in Washington, Idaho and Oregon, customer growth and decoupling. AEL&P's revenues decreased due to a decrease in retail rates associated with the federal income tax law change and the adoption of ASU No. 2014-09 effective January 1, 2018, which changed the presentation of AEL&P's utility-related taxes collected from customers from a gross basis to a net basis. The adoption of ASU No. 2014-09 decreased AEL&P's revenues and taxes other than income taxes by $2.3 million, but had no impact on net income. See "Notes 2 and 4 of the Notes to Consolidated Financial Statements" for further information on the adoption of this ASU.

Utility resource costs decreased at both Avista Utilities and AEL&P. The decrease at Avista Utilities was primarily due to a decrease in natural gas purchased (due to a decrease in prices and volumes). The decrease at AEL&P was due to a decrease in deferred power supply expenses.

Utility operating expenses increased primarily from an increase at Avista Utilities as a result of an increase in generation and distribution operating and maintenance costs and outside service costs. The increase was partially offset by a decrease in pension costs.

The acquisition costs are related to the now terminated acquisition by Hydro One. These costs decreased because 2018 consisted primarily of employee time incurred directly related to the transaction, whereas 2017 included financial advisers' fees, legal fees, consulting fees and employee time. None of these transaction costs are being passed through to customers.

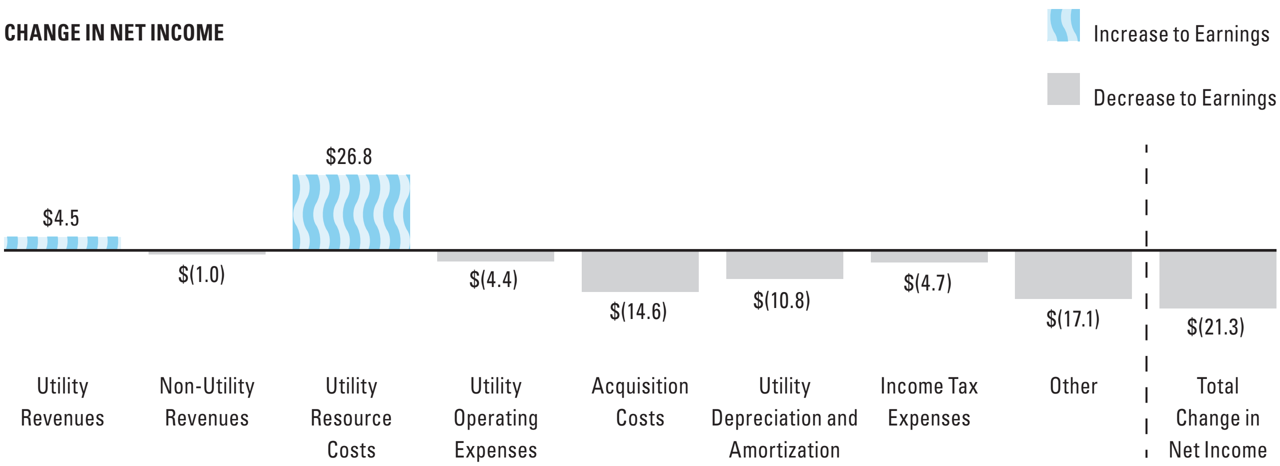
Utility depreciation and amortization increased due to additions to utility plant.

Income taxes decreased due to federal income tax law changes, which reduced the corporate tax rate from 35 percent to 21 percent. Our effective tax rate was 16.0 percent for 2018 compared to 41.7 percent for 2017. In addition to the enacted tax rate decrease, the amortization of plant excess deferred income taxes also decreased our effective tax rate. See "Note 11 of the Notes to Consolidated Financial Statements" for further details and a reconciliation of our effective tax rate.

The increase in other was primarily related to an increase in interest expense due to additional debt being outstanding during 2018 as compared to 2017. Also, there were impairment losses on investments and net losses from our equity method investments (which were partially offset by a gain from one of our equity method investments). In addition, we had increased expenses at one of our subsidiaries associated with the insolvency of the general contractor on a renovation project. The general contractor's insolvency resulted in the recording of a liability to various subcontractors.

2017 Compared to 2016

The following graph shows the total change in net income attributable to Avista Corp. shareholders for 2016 to 2017, as well as the various factors that caused such change (dollars in millions):



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 related to the now terminated 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 reduced income before income taxes, but a significant portion of these costs were not deductible for tax purposes and thus did not reduce income tax expense. However, now that the transaction has been terminated, we expect to file amended tax returns as more of the transaction costs are deductible. 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.

Non-GAAP Financial Measures

The following discussion for Avista Utilities includes two financial measures that are considered "non-GAAP financial measures," electric utility margin and natural gas utility margin. In the AEL&P section, we include a discussion of utility 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. Electric utility margin is electric operating revenues less electric resource costs, while natural gas utility margin is natural gas operating revenues less natural gas resource costs. The most directly comparable GAAP financial measure to electric and natural gas utility margin is utility operating revenues as presented in "Note 22 of the Notes to Consolidated Financial Statements."

The presentation of electric utility margin and natural gas utility margin is intended to enhance understanding of our operating performance. We use these measures internally and believe they provide useful information to investors in their analysis of how changes in loads (due to weather, economic or other conditions), rates, supply costs and other factors impact our results of operations. Changes in loads, as well as power and natural gas supply costs, are generally deferred and recovered from customers through regulatory accounting mechanisms. Accordingly, the analysis of utility margin generally excludes most of the change in revenue resulting from these regulatory mechanisms. We present electric and natural gas utility margin separately below for Avista Utilities since each business has different cost sources, cost recovery mechanisms and jurisdictions, so we believe that separate analysis is beneficial. These measures are not intended to replace utility operating revenues as determined in accordance with GAAP as an indicator of operating performance. Reconciliations of operating revenues to utility margin are set forth below.

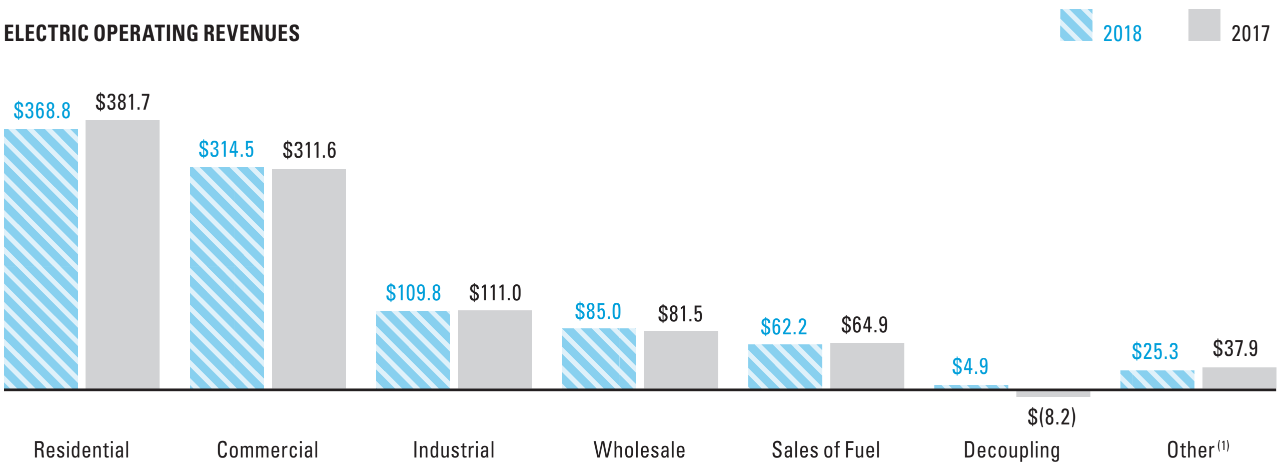
Results of Operations—Avista Utilities

2018 Compared to 2017

Utility Operating Revenues

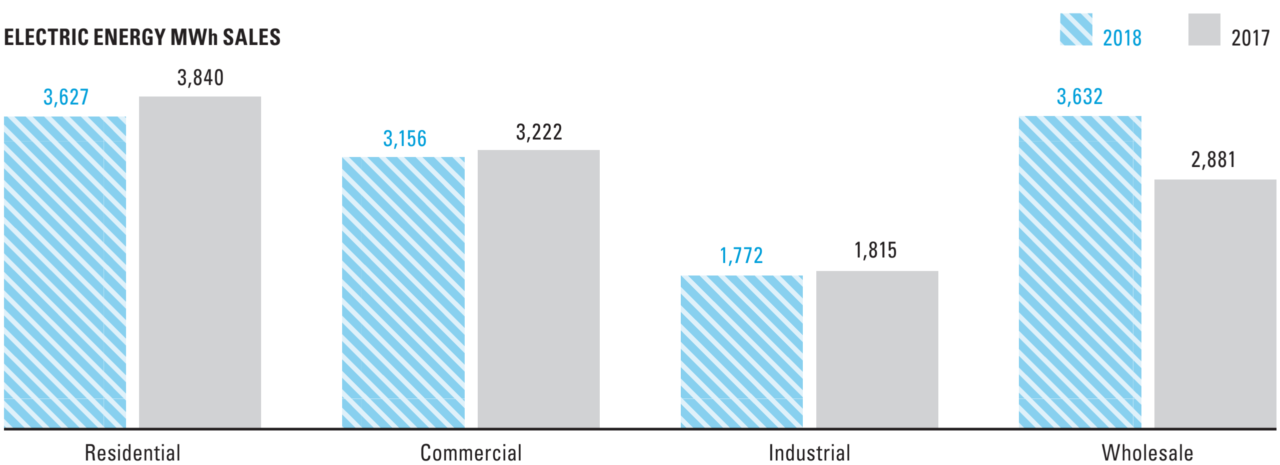
The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the years ended December 31 (dollars in millions and MWhs in thousands):

ELECTRIC OPERATING REVENUES



(1) This balance includes public street and highway lighting, which is considered part of retail electric revenues, and deferrals/amortizations to customers related to federal income tax law changes.

ELECTRIC ENERGY MWh SALES



The following table presents the current year deferrals and the amortization of prior year decoupling balances that are reflected in utility electric operating revenues for the years ended December 31 (dollars in thousands):

	Electric Operating Revenues	
	2018	**2017**
Current year decoupling deferrals [a]	$ 17,060	$ (1,937)
Amortization of prior year decoupling deferrals [b]	(12,190)	(6,283)
Total electric decoupling revenue	$ 4,870	$ (8,220)

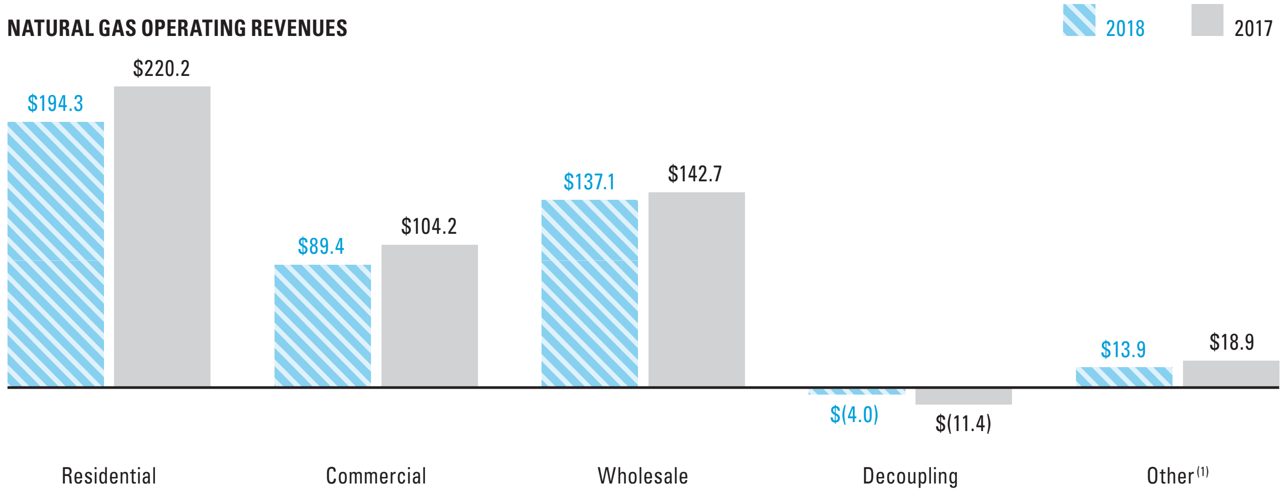
(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative numbers are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative numbers are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

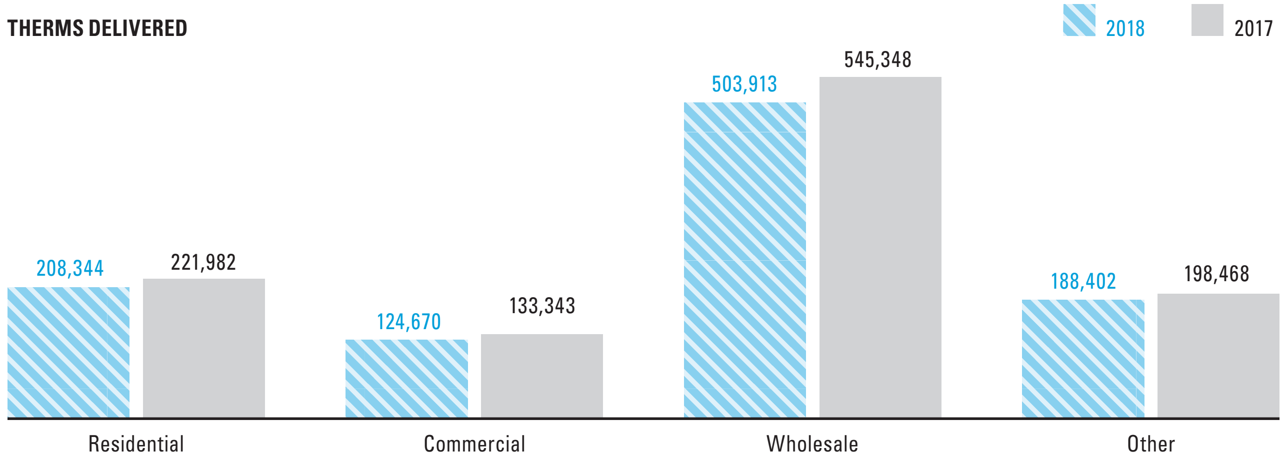
Total electric revenues decreased $9.9 million for 2018 as compared to 2017, primarily reflecting the following:

- an $11.1 million decrease in retail electric revenues due to a decrease in total MWhs sold (decreased revenues $30.2 million), partially offset by an increase in revenue per MWh (increased revenues $19.1 million).
  - The decrease in total retail MWhs sold was the result of weather that was warmer than the prior year during the heating season (which decreased electric heating loads) and cooler than the prior year during the cooling season (which decreased electric cooling loads), partially offset by customer growth. Compared to 2017, residential electric use per customer decreased 7 percent and commercial use per customer decreased 3 percent. Heating degree days in Spokane were 7 percent below normal and 9 percent below 2017. Cooling degree days in Spokane were 5 percent below normal and 30 percent below the prior year.
  - The increase in revenue per MWh was primarily due to general rate increases in Idaho (effective January 1, 2018) and Washington (effective May 1, 2018), as well as an increase in decoupling surcharge rates. This was partially offset by rate decreases associated with the lower corporate tax rate.
- a $3.5 million increase in wholesale electric revenues due to an increase in sales volumes (increased revenues $17.6 million), partially offset by a decrease in sales prices (decreased revenues $14.1 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $2.7 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 2018, $30.6 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For 2017, $35.3 million of these sales were made to our natural gas operations.
- a $13.1 million increase in electric revenue due to decoupling. Weather was warmer than normal during the heating season and cooler than normal during the cooling season in 2018, which resulted in decoupling surcharges.
- a $9.9 million decrease in electric revenue due to net deferrals for refunds to customers related to the federal income tax law changes (included in other revenue in the graph above) that lowered the corporate tax rate from 35 percent to 21 percent. As our customers' rates had the 35 percent corporate tax rate built in from prior general rate cases through May 1, 2018 in Washington and June 1, 2018 in Idaho, we deferred the impact of the change beginning January 1, 2018. Effective May 1, 2018 in Washington and June 1, 2018 in Idaho, base rates reflect the lower 21 percent corporate tax.
- a $2.4 million decrease in transmission revenue (included in other revenue in the graph above).

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):



(1) This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues, and deferrals/amortizations to customers related to federal income tax law changes.



The following table presents the current year deferrals and the amortization of prior year decoupling balances that are reflected in natural gas operating revenues for the years ended December 31 (dollars in thousands):

	Natural Gas Operating Revenues	
	2018	**2017**
Current year decoupling deferrals [a]	$ 3,168	$ (4,315)
Amortization of prior year decoupling deferrals [b]	(7,130)	(7,059)
Total natural gas decoupling revenue	$ (3,962)	$ (11,374)

(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative numbers are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative numbers are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total natural gas revenues decreased $43.9 million for 2018 as compared to 2017, primarily reflecting the following:

- a $41.6 million decrease in retail natural gas revenues due to a decrease in volumes (decreased revenues $18.9 million) and lower retail rates (decreased revenues $22.7 million).
  - We sold less retail natural gas in 2018 as compared to 2017 primarily due to warmer weather during the heating season, partially offset by customer growth. Compared to 2017, residential use per customer decreased 8 percent and commercial use per customer decreased 7 percent. Heating degree days in Spokane were 7 percent below normal for 2018, and 9 percent below 2017. Heating degree days in Medford were 3 percent below normal for 2018, and 2 percent below 2017.
  - Lower retail rates were due to PGAs and rate decreases associated with the lower corporate tax rate, partially offset by general rate increases in Washington, Oregon and Idaho.
- a $5.6 million decrease in wholesale natural gas revenues due to a decrease in volumes (decreased revenues $11.2 million), partially offset by an increase in prices (increased revenues $5.6 million). In 2018, $44.7 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In 2017, $49.3 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 $7.4 million increase in natural gas revenue due to decoupling. Weather was warmer than normal during the heating season in 2018, which resulted in decoupling surcharges.
- a $5.5 million decrease in natural gas revenue due to net deferrals for refunds to customers related to the federal income tax law changes (included in other revenue in the graph above) that lowered the corporate tax rate from 35 percent to 21 percent. As our customers' rates had the 35 percent corporate tax rate built in from prior general rate cases through May 1, 2018 in Washington and June 1, 2018 in Idaho, we deferred the impact of the change beginning January 1, 2018. Effective May 1, 2018 in Washington and June 1, 2018 in Idaho, base rates reflect the lower 21 percent corporate tax. Base rates in Oregon continue to have the 35 percent corporate tax rate built in and we are deferring the impact.

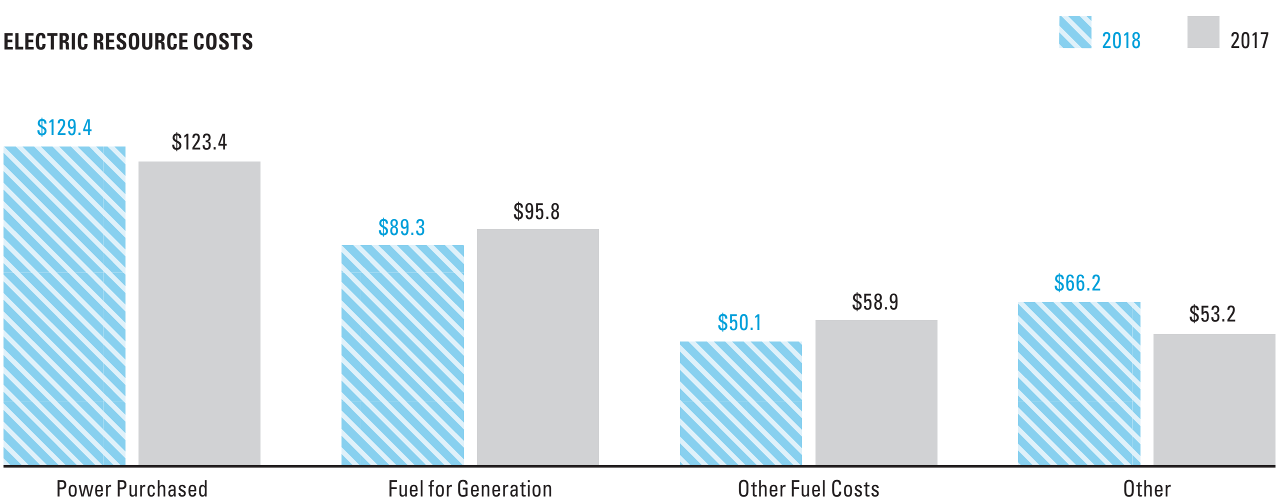
The following table presents Avista Utilities' average number of electric and natural gas retail customers for the years ended December 31:

	Electric Customers		Natural Gas Customers	
	2018	**2017**	**2018**	**2017**
Residential	340,308	334,848	314,800	307,375
Commercial	42,618	42,154	35,488	35,192
Interruptible	—	—	39	37
Industrial	1,318	1,328	246	251
Public street and highway lighting	594	569	—	—
Total retail customers	384,838	378,899	350,573	342,855

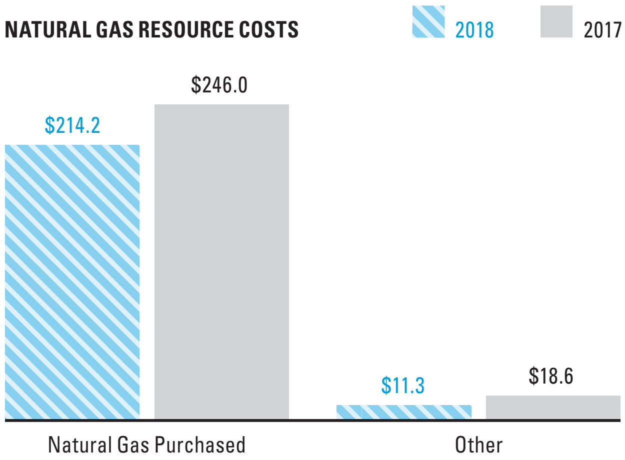
Utility Resource Costs

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 $44.7 million and $49.3 million for 2018 and 2017, respectively.



Total natural gas resource costs in the graph above include intracompany resource costs of $30.6 million and $35.3 million for 2018 and 2017, respectively.

Total electric resource costs increased $3.8 million for 2018 as compared to 2017 primarily due to the following:

- a $6.0 million increase in power purchased due to an increase in the volume of power purchases (increased costs $10.8 million), partially offset by a decrease in wholesale prices (decreased costs $4.8 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $6.5 million decrease in fuel for generation primarily due to a decrease in fuel prices. We also had a decrease in thermal generation at Colstrip and Coyote Springs 2 due to outages; however, this was offset by an increase in thermal generation at the Lancaster Plant.
- an $8.8 million decrease in other fuel costs.
- a $5.3 million increase from amortizations and deferrals of power costs (included in other resource costs in the graph above). This change was primarily the result of lower net power supply costs.
- a $7.8 million increase in other regulatory amortizations (included in other resource costs in the graph above).

Total natural gas resource costs decreased $39.1 million for 2018 as compared to 2017 primarily reflecting the following:

- a $31.8 million decrease in natural gas purchased due to a decrease in total therms purchased (decreased costs $16.1 million) and a decrease in the price of natural gas (decreased costs $15.7 million).
- a $4.7 million decrease from amortizations and deferrals of natural gas costs (included in other resource costs in the graph above).
- a $2.6 million decrease in other regulatory amortizations (included in other resource costs in the graph above).

Utility Margin

The following table reconciles Avista Utilities' operating revenues, as presented in "Note 22 of the Notes to Consolidated Financial Statements" to the Non-GAAP financial measure utility margin for the years ended December 31 (dollars in millions):

	Electric		Natural Gas		Intracompany		Total	
	2018	2017	2018	2017	2018	2017	2018	2017
Operating revenues	$ 970,538	$ 980,390	$ 430,705	$ 474,649	$ (75,277)	$ (84,680)	$ 1,325,966	$ 1,370,359
Resource costs	335,035	331,254	225,473	264,589	(75,277)	(84,680)	485,231	511,163
Utility margin	$ 635,503	$ 649,136	$ 205,232	$ 210,060	$ —	$ —	$ 840,735	$ 859,196

Electric utility margin decreased $13.6 million and natural gas utility margin decreased $4.8 million.

The primary reason for the decrease in both electric and natural gas utility margin was federal income tax law changes that lowered the corporate tax rate from 35 percent to 21 percent. As our customers' rates continued to have the 35 percent corporate tax rate built in from prior general rate cases, we deferred the impact of the change beginning January 1, 2018. Effective May 1, 2018 in Washington and June 1, 2018 in Idaho, base rates reflect the lower 21 percent corporate tax. As such, we are no longer deferring the tax rate change in these jurisdictions. There is no impact to our net income as there was a corresponding decrease in income tax expense.

Electric utility margin was positively impacted during 2018 by general rate increases in Idaho (effective January 1, 2018) and Washington (effective May 1, 2018), as well as customer growth. For 2018, we recognized a pre-tax benefit of $6.1 million under the ERM in Washington compared to a benefit of $4.6 million for 2017.

Natural gas utility margin was positively impacted by general rate increases in Oregon (effective October 1 and November 1, 2017), Idaho (effective January 1, 2018) and Washington (effective May 1, 2018), as well as customer growth.

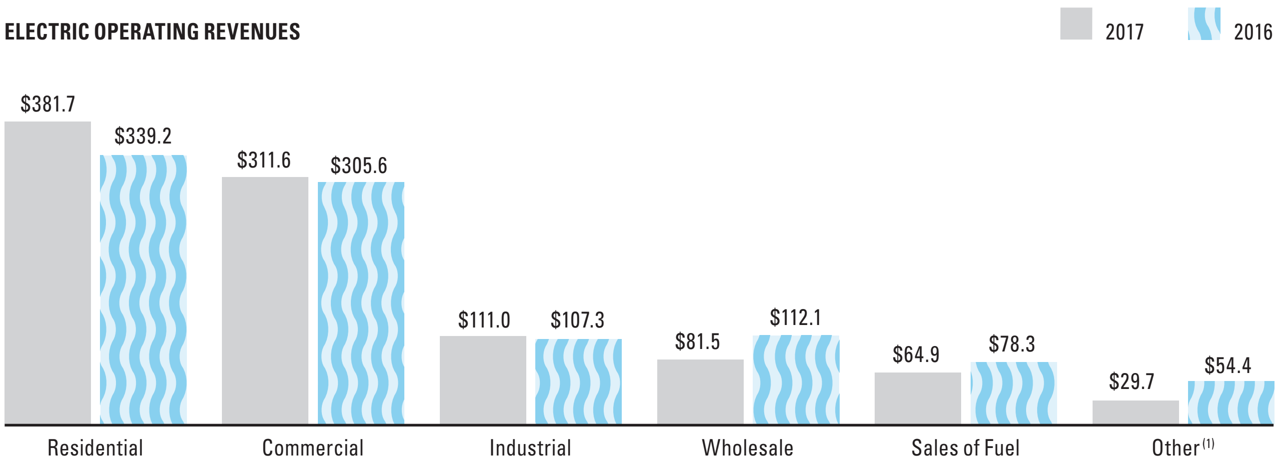
Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (as fuel for our generation plants). These transactions are eliminated in the presentation of total results for Avista Utilities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

2017 Compared to 2016

Utility Operating Revenues

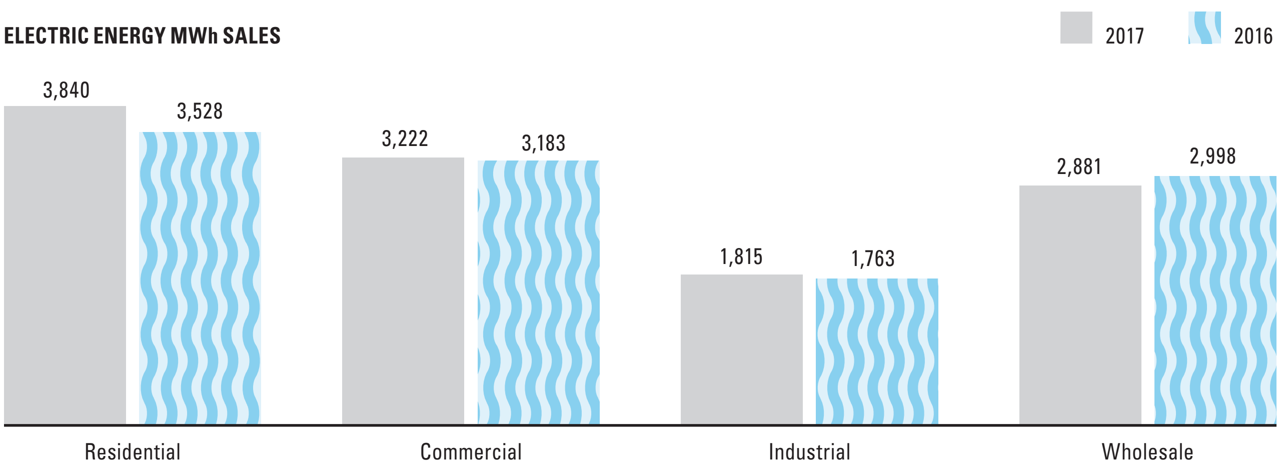
The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the years ended December 31 (dollars in millions and MWhs in thousands):

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 the current year deferrals and the amortization of prior year decoupling balances that are reflected in utility electric operating revenues for the years ended December 31 (dollars in thousands):

	Electric Operating Revenues	
	2017	**2016**
Current year decoupling deferrals [a]	$ (1,937)	$ 18,033
Amortization of prior year decoupling deferrals [b]	(6,283)	(684)
Total electric decoupling revenue	$ (8,220)	$ 17,349

(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative numbers are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

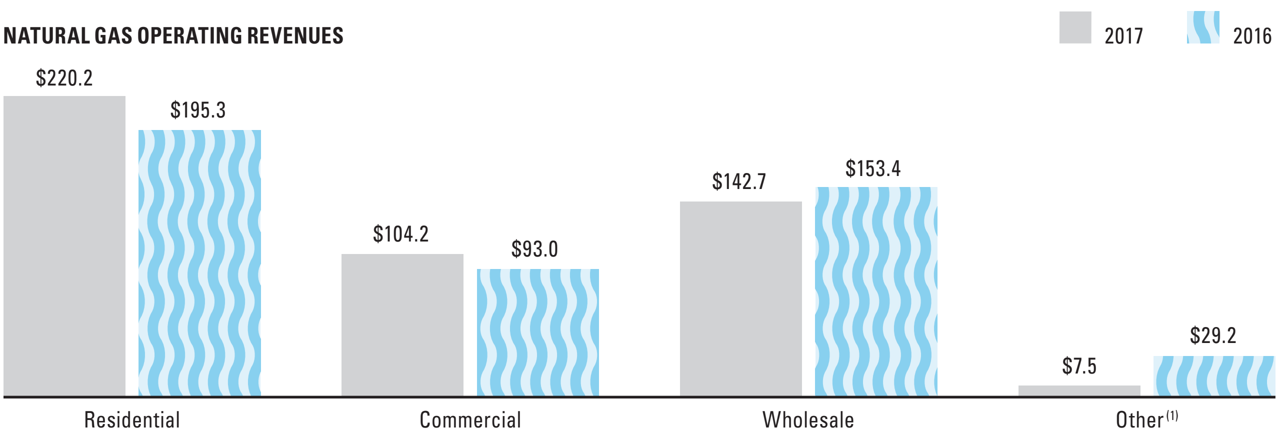
(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative numbers are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

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.

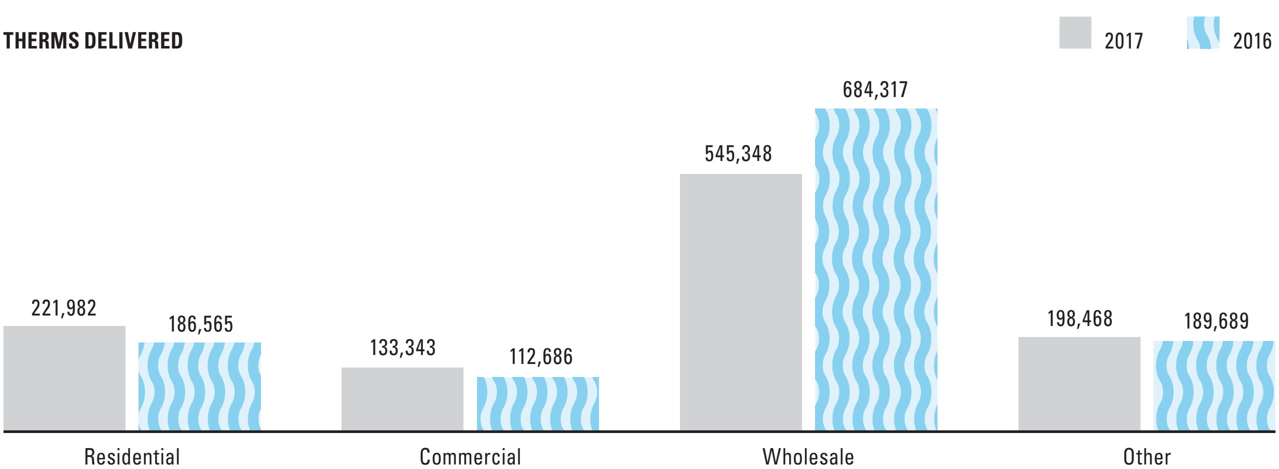
The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for the years ended December 31 (dollars in millions and therms in thousands):

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 the current year deferrals and the amortization of prior year decoupling balances that are reflected in natural gas operating revenues for the years ended December 31 (dollars in thousands):

	Natural Gas Operating Revenues	
	2017	2016
Current year decoupling deferrals [a]	$ (4,315)	$ 13,565
Amortization of prior year decoupling deferrals [b]	(7,059)	(1,256)
Total natural gas decoupling revenue	$ (11,374)	$ 12,309

(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative numbers are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative numbers are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

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

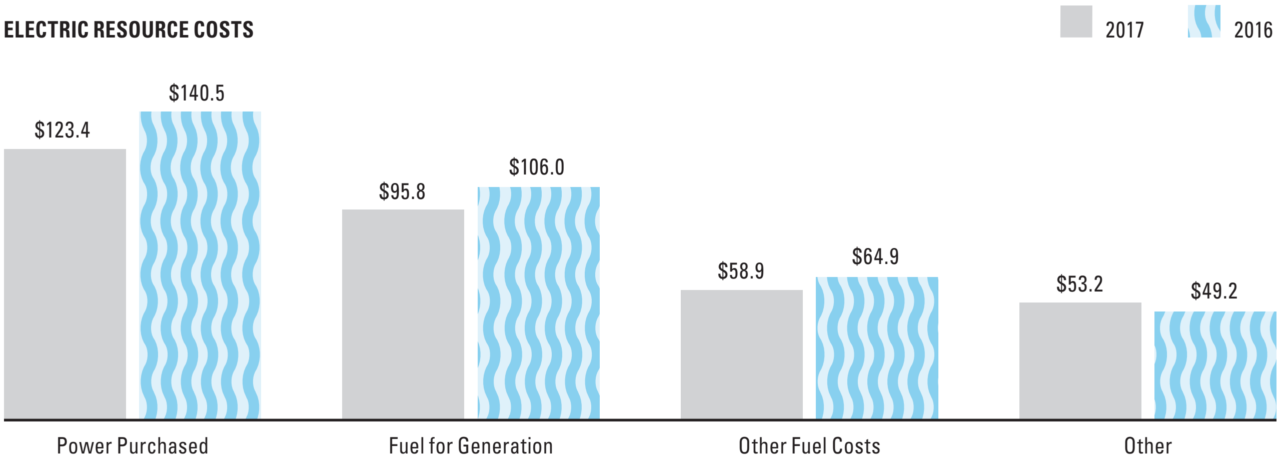
- a $36.3 million increase in retail natural gas revenues due to an increase in volumes (increased revenues $51.2 million), partially offset by lower retail rates (decreased revenues $14.9 million).
  - We sold more retail natural gas in 2017 as compared to 2016 primarily due to cooler weather in the 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:

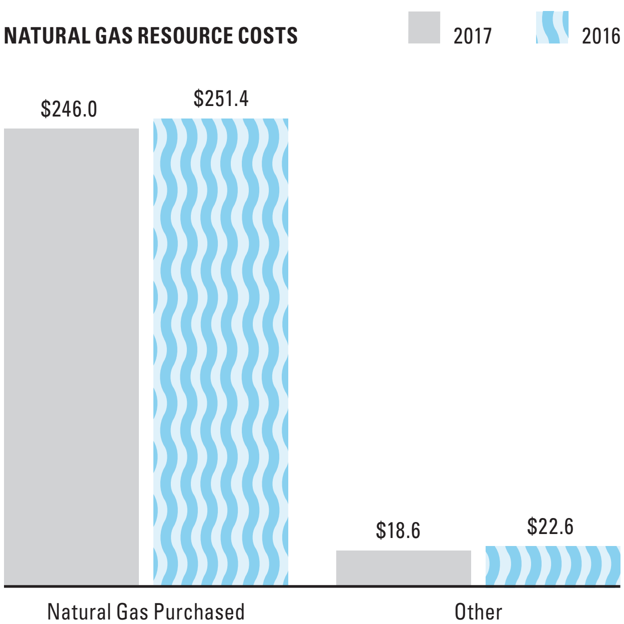
	Electric Customers		Natural Gas Customers	
	2017	2016	2017	2016
Residential	334,848	330,699	307,375	300,883
Commercial	42,154	41,785	35,192	34,868
Interruptible	—	—	37	37
Industrial	1,328	1,342	251	255
Public street and highway lighting	569	558	—	—
Total retail customers	378,899	374,384	342,855	336,043

Utility Resource Costs

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



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.



Total natural gas resource costs in the graph 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 (included in other resource costs in the graph above).
- a $0.5 million decrease in other electric resource costs (included in other resource costs in the graph above).
- a $3.0 million increase in other regulatory amortizations (included in other resource costs in the graph above).

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 (included in other resource costs in the graph above).
- a $2.6 million increase in other regulatory amortizations (included in other resource costs in the graph above).

Utility Margin

The following table reconciles Avista Utilities' operating revenues, as presented in "Note 22 of the Notes to Consolidated Financial Statements" to the Non-GAAP financial measure utility 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
Utility margin	$ 649,136	$ 636,368	$ 210,060	$ 196,918	$ —	$ —	$ 859,196	$ 833,286

Electric utility margin increased $12.8 million and natural gas utility margin increased $13.1 million.

The increase in electric utility 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 pre-tax benefit of $5.1 million for 2016.

The increase in natural gas utility 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 above.

Results of Operations—Alaska Electric Light and Power Company

2018 Compared to 2017

Net income for AEL&P was $8.3 million for the year ended December 31, 2018, compared to $9.1 million for 2017.

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

	Electric	
	2018	2017
Operating revenues	$ 43,599	$ 53,027
Resource costs	9,505	13,403
Utility margin	$ 34,094	$ 39,624

Electric revenues decreased for 2018 primarily due to the accrual for refunds to customers related to the federal income tax law changes that lowered the corporate tax rate from 35 percent to 21 percent. AEL&P recorded a customer refund liability of $1.7 million related to this tax law change, which was returned to customers during 2018. Effective August 1, 2018, retail rates to customers were reduced to reflect the lower corporate tax rate. For the full year of 2018 there was no impact to net income as there was a corresponding decrease in income tax expense. In addition to the above, there was a decrease in sales volumes to residential and commercial customers, primarily during the fourth quarter when winter rates are in effect.

Effective January 1, 2018, due to the adoption of ASU No. 2014-09 (revenue recognition standard), AEL&P no longer records utility-related taxes collected from customers on a gross basis in revenue and taxes other than income taxes. These taxes are currently recorded on a net basis within revenue. This change in accounting reduced 2018 revenue, utility margin and taxes other than income taxes by $2.3 million for 2018 as compared to 2017 with no impact to net income.

For operating expenses, there was a slight decrease in other operating expenses for 2018 primarily due to a decrease in generation maintenance and supplies expense, partially offset by an increase in transmission and distribution maintenance expenses.

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 utility 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
Utility margin	$ 39,624	$ 34,262

In 2017, there was an increase in utility 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 was included in utility margin for 2017. The increase in utility 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.

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.

Results of Operations—Other Businesses

2018 Compared to 2017

The net loss from these operations was $6.7 million for 2018 compared to a net loss of $7.9 million for 2017. Losses at our other businesses decreased during 2018 as 2017 included a one-time tax expense in the fourth quarter from revaluing deferred taxes to the new tax rate of 21 percent as a result of federal income tax law changes. We also had a gain during 2018 from one of our equity investments. This was partially offset by increased expenses at one of our subsidiaries associated with the insolvency of the general contractor on a renovation project. The general contractor's insolvency resulted in the recording of a liability to various subcontractors. There were also impairment losses and an increase in equity method losses on our other investments.

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 an 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.

Accounting Standards to be Adopted in 2019

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 2019. While not expected to have a material impact, we do expect the adoption of the ASU No. 2016-02 "Leases (Topic 842)" effective January 1, 2019 to result in a right of use asset and lease liability of between $65.0 million and $75.0 million, not including the Snettisham finance lease (formerly a capital lease) of $57.2 million, which is already included on the Consolidated Balance Sheet as of December 31, 2018. For information on accounting standards adopted in 2018 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 21 of the Notes to Consolidated Financial Statements" for further discussion of our regulatory accounting policy and mechanisms.
- **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.

We record 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. If we concluded that recovery of interest rate 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.

- **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 20 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 $22.8 million for 2018, $26.5 million for 2017 and $26.8 million for 2016. Of our pension costs (excluding the SERP), 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):

	2018	2017	2016
Discount rate (exclusive of SERP)			
Pension discount rate	4.31%	3.71%	4.26%
Increase/(decrease) to projected benefit obligation	$ (54.7)	$ 49.2	$ 27.7
Return on plan assets [(a)]			
Expected long-term return on plan assets	5.50%	5.87%	5.30%
Increase/(decrease) to pension costs	$ 2.2	$ (2.5)	$ (0.5)
Actual return on plan assets—net of fees	(7.00)%	15.60%	8.10%
Actual gain/(loss) on plan assets	$ (41.0)	$ 82.5	$ 43.2

(a) The SERP has no plan assets. The plan assets in this disclosure are for the pension plan only.

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)%	$ —*	$ 3.0
Expected long-term return on plan assets	0.5%	—*	(3.0)
Discount rate	(0.5)%	45.0	4.4
Discount rate	0.5%	(40.2)	(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, 2018 by $8.1 million and the service and interest cost by $0.6 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, 2018 by $6.4 million and the service and interest cost by $0.5 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, 2018, we had $199.5 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

2018 compared to 2017

Consolidated Operating Activities

Net cash provided by operating activities was $361.9 million for 2018 compared to $410.3 million for 2017. The decrease in net cash provided by operating activities was primarily the result of the enactment of the TCJA, which caused a decrease in deferred income taxes due to the loss of the bonus depreciation tax deduction. In addition, this also impacted income taxes receivable as we are now in a payable position for federal income taxes whereas in prior years we were in receivable positions. See "Note 11 of the Notes to Consolidated Financial Statements" for further discussion of the TCJA. In addition, the settlement of interest rate swaps decreased operating cash flows as we paid a net amount of $26.6 million during 2018 compared to $8.8 million paid during 2017.

The decreases above, were partially offset by an increase in net income from $115.9 million in 2017 to $136.6 million in 2018 and a decrease in collateral required for derivative instruments in 2018 compared to 2017.

Consolidated Investing Activities

Net cash used in investing activities was $440.4 million for 2018, an increase compared to $434.1 million for 2017. During 2018, we paid $424.4 million for utility capital expenditures, compared to $412.3 million for 2017. In addition, during 2018, our subsidiaries invested net cash of $13.7 million for notes receivable to third parties, equity investments and property investments, compared to $15.5 million in 2017.

Consolidated Financing Activities

Net cash provided by financing activities was $77.0 million for 2018 compared to $31.5 million for 2017. The increase in financing cash flows was primarily the result of an increase in short-term borrowings. During 2018 because we issued an insignificant amount of common stock due to the now terminated Hydro One transaction, we had to increase short-term borrowings to finance capital expenditures and for other corporate purposes. During 2017 we issued common stock for these purposes. Our net long-term debt (maturities and issuances) in both 2018 and 2017 increased by approximately $90 million. The increases above were partially offset by an increase in cash dividends paid to $98.0 million (or $1.49 per share) for 2018 compared to $92.5 million (or $1.43 per share) for 2017.

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 $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).

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),
- cash dividends paid of $87.2 million (or $1.37 per share),
- $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).

Capital Resources

Capital Structure

Our consolidated capital structure, including the current portion of long-term debt and capital leases, and short-term borrowings, and excluding noncontrolling interests, consisted of the following as of December 31, 2018 and 2017 (dollars in thousands):

	December 31, 2018		December 31, 2017	
	Amount	Percent of Total	Amount	Percent of Total
Current portion of long-term debt and capital leases	$ 107,645	2.8%	$ 277,438	7.6%
Short-term borrowings	190,000	4.9%	105,398	2.9%
Long-term debt to affiliated trusts	51,547	1.3%	51,547	1.4%
Long-term debt and capital leases	1,755,529	45.3%	1,491,799	40.8%
Total debt	2,104,721	54.3%	1,926,182	52.7%
Total Avista Corporation shareholders' equity	1,773,220	45.7%	1,729,828	47.3%
Total	$ 3,877,941	100.0%	$ 3,656,010	100.0%

Our shareholders' equity increased $43.4 million during 2018 primarily due to net income, 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, 2018, there was $199.5 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, 2018, we were in compliance with this covenant with a ratio of 54.3 percent.

AEL&P has a $25.0 million committed line of credit that expires in November 2019. As of December 31, 2018, there were no borrowings or letters of credit outstanding under this committed line of credit.

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, 2018, 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):

	2018	2017	2016
Balance outstanding at end of year	$ 190,000	$ 105,000	$ 120,000
Letters of credit outstanding at end of year	$ 10,503	$ 34,420	$ 34,353
Maximum balance outstanding during the year	$ 200,000	$ 254,500	$ 280,000
Average balance outstanding during the year	$ 58,199	$ 133,027	$ 171,090
Average interest rate during the year	2.80%	1.88%	1.26%
Average interest rate at end of year	3.18%	2.26%	1.50%

As of December 31, 2018, 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 May 2018, we issued and sold $375.0 million of 4.35 percent first mortgage bonds due in 2048 through a public offering. The total net proceeds from the sale of the bonds were used to repay maturing long-term debt of $272.5 million, repay the outstanding balance under our $400.0 million committed line of credit and for other general corporate purposes. In connection with the issuance and sale of the first mortgage bonds, we cash-settled fourteen interest rate swap derivatives (notional aggregate amount of $275.0 million) and paid a net amount of $26.6 million. The effective interest rate of the first mortgage bonds is 4.87 percent, including the effects of the settled interest rate swap derivatives and issuance costs.

Equity Issuances

We have four separate sales agency agreements under which the sales agents may offer and sell new shares of our common stock from time to time. No shares were issued under these agreements during 2018. These agreements provide for the offering of a maximum of 3.8 million shares, of which approximately 1.1 million remain unissued as of December 31, 2018. Subject to the satisfaction of customary conditions (including any required regulatory approvals), the Company has the right to increase the maximum number of shares that may be offered under these agreements.

2019 Liquidity Expectations

In January 2019, we received a $103 million termination fee from Hydro One in connection with the termination of the proposed acquisition. The termination fee will be used for reimbursing our transaction costs incurred from 2017 to 2019. These costs, including income taxes, total approximately $51 million. The balance of the termination fee will be used for general corporate purposes and reduces our need for external financing.

After consideration of the net termination fee received from Hydro One, during 2019, we expect to issue approximately $165.0 million of long-term debt and up to $50.0 million of equity in order to refinance maturing long-term debt, fund planned capital expenditures and maintain an appropriate capital structure.

After considering the expected issuances of long-term debt and equity during 2019, 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.

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, 2018, we could issue $1.2 billion of additional preferred stock at an assumed dividend rate of 7.4 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, 2018, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.2 billion in aggregate principal amount of additional first mortgage bonds at Avista Corp. and $27.0 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.

Utility Capital Expenditures

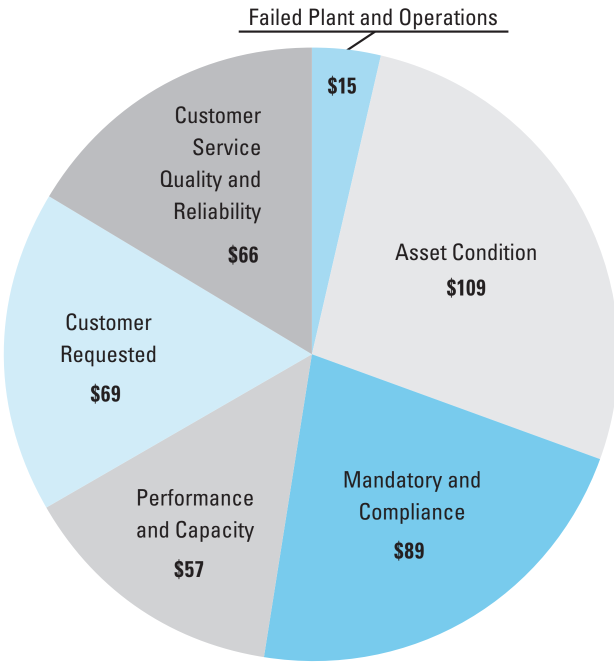
We are making capital investments at our utilities to enhance service and system reliability for our customers and replace aging infrastructure.

The following table summarizes our actual and expected capital expenditures as of and for the year ended December 31, 2018 (in thousands):

	Avista Utilities	AEL&P
2018 Actual capital expenditures		
Capital expenditures (per the Consolidated Statement of Cash Flows)	$ 418,741	$ 5,609
Expected total annual capital expenditures (by year)		
2019	$ 405,000	$ 9,000
2020	405,000	7,000
2021	405,000	7,000

The following graph shows Avista Utilities' capital budget for 2019:

CAPITAL BUDGET AT AVISTA UTILITIES FOR 2019
(dollars in millions)



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

Non-Regulated Investments and Capital Expenditures

We are making investments and capital expenditures at our other businesses including those related to economic development projects in our service territory that will demonstrate the latest energy and environmental building innovations and house several local college degree programs. In addition, we are making investments in emerging technology companies and venture capital funds.

The following table summarizes our actual and expected investments and capital expenditures at our other businesses as of and for the year ended December 31, 2018 (in thousands):

		Other
2018 Actual investments and capital expenditures		
Investments and capital expenditures		
(per the Consolidated Statement of Cash Flows)	$	14,174
Expected total annual investments and capital expenditures (by year)		
2019	$	19,000
2020		9,000
2021		11,000

These estimates of investments and capital expenditures are subject to continuing review and adjustment. Actual expenditures may vary from our estimates due to factors such as changes in business conditions or strategic plans.

Off-Balance Sheet Arrangements

As of December 31, 2018, we had $10.5 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $34.4 million as of December 31, 2017.

Pension Plan

We contributed $22.0 million to the pension plan in 2018. We expect to contribute a total of $110.0 million to the pension plan in the period 2019 through 2023, 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 19, 2019:

	Standard & Poor's (1)	Moody's (2)
Corporate/Issuer rating	BBB	Baa2
Senior secured debt	A-	A3
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 20, 2018, Moody's downgraded our issuer rating from Baa1 to Baa2 and our senior secured and first mortgage bond ratings from A2 to A3. Moody's made these downgrades because of the impacts of the TCJA, which results in less operating cash flow from deferred income taxes due to the loss of bonus depreciation and lower tax rates. Moody's also expressed less predictability with regulatory outcomes in Washington as a contributing factor for the downgrade.

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

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, 2018 (dollars in millions):

	2019	2020	2021	2022	2023	Thereafter
Avista Utilities:						
Long-term debt maturities	$ 90	$ 52	$ —	$ 250	$ 14	$ 1,325
Long-term debt to affiliated trusts	—	—	—	—	—	52
Interest payments on long-term debt (1)	83	79	77	67	63	1,238
Short-term borrowings	190	—	—	—	—	—
Energy purchase contracts (2)	269	235	201	197	188	1,288
Operating lease obligations (3)	5	4	4	4	4	99
Other obligations (4)	29	33	32	28	29	196
Information technology contracts (5)	1	1	—	—	—	—
Pension plan funding (6)	22	22	22	22	22	—
Unsettled interest rate swap derivatives (7)	(5)	(1)	6	(2)	—	—
AEL&P total contractual obligations (8)	15	15	16	16	16	268
Other businesses (consolidated) total contractual obligations (9)	22	4	1	—	—	3
Total contractual obligations	$ 721	$ 444	$ 359	$ 582	$ 336	$ 4,469

(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, 2018.

(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 payments of $4.0 million annually for an operating lease, which has historically been included as a generation facility contractual commitment (number 4 below). The operating lease expires in 2047.

(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 2023. We cannot reasonably estimate pension plan contributions beyond 2023 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, 2018. 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 $0.5 million that is 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 $18.3 million remaining asset retirement obligations as of December 31, 2018.

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, 2018 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 2019, 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 2017 and 2018. In Spokane, Washington employment growth was 2.3 percent with gains in all major sectors except financial activities. Employment increased by 3.2 percent in Coeur d'Alene, Idaho, reflecting gains in all major sectors except manufacturing, information, and government. In Medford, Oregon, employment growth was 2.8 percent, with gains in all major sectors except trade, transportation, and utilities and government. U.S. nonfarm sector jobs grew by 1.6 percent over the same period.

Seasonally adjusted average unemployment rates went down in 2018 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the average rate was 5.6 percent in 2017 and declined to 5.5 percent in 2018; in Coeur d'Alene the average rate declined from 3.8 percent to 3.4 percent; and in Medford the average rate declined from 4.8 percent to 4.7 percent. The U.S. rate declined from 4.4 percent to 3.9 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 0.4 percent between the first half of 2017 and first half of 2018. The employment decline was centered in government, construction, manufacturing, information, financial activities, professional and business services, and education and health services. Government (including active duty military personnel) accounts for approximately 37 percent of total employment. Between 2018 and 2019, the non-seasonally adjusted unemployment rate decreased from 4.7 percent to 4.5 percent.

Forecasted Customer and Load Growth

Based on our forecast for 2019 through 2022 for Avista Utilities' service area, we expect annual electric customer growth to average 1 percent, within a forecast range of 0.6 percent to 1.4 percent. We expect annual natural gas customer growth to average 1.4 percent, within a forecast range of 0.8 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 1.1 percent, within a forecast range of 0.6 percent and 1.6 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 no significant growth in residential, commercial and government customers for the period 2019 through 2022. 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 and commercial 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. Colstrip, Kettle Falls GS and Rathdrum CT all require CAA Title V operating permits. The Boulder Park GS, Northeast CT 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)

On April 16, 2016, the Mercury Air Toxic Standards (MATS), an EPA rule for coal and oil-fired sources, became effective for all Colstrip units.

Colstrip performs compliance assurance stack testing on a quarterly basis to meet the MATS site-wide limitation for Particulate Matter (PM) emissions (0.03 lbs./MMBtu). The Montana Department of Environmental Quality (MDEQ) was notified of a PM emission deviation by Talen, the plant operator, on June 28, 2018 for the testing performed on June 21, 2018. As a result, Unit 3 was immediately removed from service. Similarly, Unit 4 was removed from service on June 29, 2018.

Talen proposed, and the MDEQ acknowledged, that limited operation of Units 3 & 4 for the evaluation of a corrective action and/or data gathering related to potential corrective action was a prudent approach to solving the issue. An extensive inspection was conducted including: the coal supply, coal mills, boiler, combustion, ductwork, air preheater, scrubbers, and the stack. Talen implemented cleaning, adjustments, troubleshooting, testing, and other corrective actions. As a part of the corrective action, new flow balancing plates were installed in all Unit 3 & 4 scrubber vessels to further enhance PM removal efficiency.

PM testing in September 2018 on Units 3 & 4 demonstrated compliance with the MATS. Both of these compliance tests were witnessed by the MDEQ. With the passing of the PM testing with MATS compliance, Talen returned both Units 3 & 4 to service in September 2018.

Due to the June 2018 failure to meet the MATS standard, Colstrip Units 3 & 4 are now subject to potential MDEQ enforcement action.

The extent of this action remains under investigation. Due to the complicated nature of the compliance calculation and the various factors that MDEQ may consider, we are unable to anticipate the extent of the impending enforcement action at this time.

In December 2018, the EPA proposed to revise earlier findings and make a new determination that is not "appropriate and necessary" to regulate hazardous air pollutants from power plants. The EPA proposes this conclusion based on new cost/benefit analysis. The EPA is taking comments on this proposal, which contains additional measures, for 60 days from publication. Because Colstrip has already implemented applicable MATS control measures, it is unclear what, if any, impact the EPA's most recent proposal will have.

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. The CCR rule has been the subject of ongoing litigation. In August 2018, the D.C. Circuit struck down provisions of the rule. Colstrip, of which we are a 15 percent owner of Units 3 & 4, produces this byproduct. The rule includes 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 Colstrip owners developed a multi-year compliance plan to address the CCR requirements and existing state obligations (expressed largely through a 2012 Administrative Order on Consent). These requirements continue despite the 2018 federal court ruling.

Based on available information from Talen, 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, under a 2012 Administrative Order on Consent, the owners of Colstrip are required to provide financial assurance, primarily in the form of surety bonds, to secure each owner's pro rata share of various anticipated closure and remediation obligations. The amount of financial assurance required of each owner may, like the ARO, vary substantially due to the uncertainty and evolving nature of anticipated closure and remediation activities, and as those activities are completed over time.

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 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, 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 and related requirements through the ratemaking process.

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 fire risks, 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 (CPP) and the Carbon Pollution Standards (CPS) in August 2015. The CPP and the CPS were both intended to reduce the carbon dioxide (CO2) emissions from certain coal-fired and natural gas electric generating units (EGUs). These rules were published in the Federal Register in October 2015.

The CPP was promulgated pursuant to Section 111(d) of the CAA and applied to CO2 emissions from existing EGUs. The CPP was intended to reduce national CO2 emissions by approximately 32 percent below 2005 levels by 2030. The CPS rule was issued pursuant to Section 111(b) of the CAA and applied to the emissions of new, modified and reconstructed EGUs. The promulgated and proposed rulemakings mentioned above were legally challenged in multiple venues. 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 CPP replacement rule.

On August 31, 2018 the EPA issued a proposed replacement rule to the CPP, called the Affordable Clean Energy (ACE) rule. ACE proposes heat rate improvements as the best system of emissions reduction. The proposed rule also includes implementation guidelines for CAA section 111(d) as well as revisions to the New Source Review program. The public comment period for the rule ended October 30, 2018. 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, as well as increase the cost of wholesale electricity. Given these ongoing developments, we cannot at this time predict the outcome or estimate the extent to which our facilities may be impacted by the proposed ACE rule. 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. The Governors and Legislatures of both states began drafting climate-related proposals in late 2018, ahead of the 2019 legislative sessions. While we are unable to predict any outcome of these efforts, we are engaged with key parties in these policy deliberations.

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 reviews the standard every five years. In September 2018, it adopted a new standard of 925 pounds of GHG per MWh. We intend to seek recovery of costs related to ongoing and new requirements 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. The EIA 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.

Clean Air Rule

In September 2016, 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. On April 27, 2018, the Superior Court entered its order invalidating the CAR. Ecology has since appealed the ruling, and the Washington State Supreme Court has accepted review. The matter remains pending before the Washington Supreme Court; consequently, we cannot 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 Units 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 Colstrip 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, Colstrip 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 Colstrip 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, 2018 was $122.4 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 Colstrip 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.

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 20 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
- Cyber and 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."

Our Regulatory department is critical in mitigation of financial risk 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. Oversight of our financial risk mitigation strategies is performed by senior management and the Finance Committee of our Board of Directors.

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 post-retirement 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 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 following table summarizes our interest rate swap derivatives outstanding as of December 31, 2018 and December 31, 2017 (dollars in thousands):

	December 31, 2018	December 31, 2017
Number of agreements	21	29
Notional amount	$ 235,000	$ 450,000
Mandatory cash settlement dates	2019 to 2022	2018 to 2022
Short-term derivative assets [1]	$ 5,283	$ 2,327
Long-term derivative assets [1]	4,843	2,576
Short-term derivative liability [1] [2]	—	(34,447)
Long-term derivative liability [1] [2]	(6,861)	(1,522)

(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, 2018 and December 31, 2017 reflects the offsetting of $0.5 million and $35.0 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, 2018 would increase the interest rate swap derivative net asset by $4.3 million, while a 10-basis-point decrease would decrease the interest rate swap derivative net asset by $4.4 million.

We estimated that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2017 would have decreased 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.

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, 2018 (dollars in thousands):

	2019	2020	2021	2022	2023	Thereafter	Total	Fair Value
Fixed rate long-term debt [1]	$ 105,000	$ 52,000	$ —	$ 250,000	$ 13,500	$ 1,400,000	$ 1,820,500	$ 1,877,034
Weighted-average interest rate	5.22%	3.89%	—	5.13%	7.35%	4.64%	4.74%	
Variable rate long-term debt to affiliated trusts	—	—	—	—	—	$ 51,547	$ 51,547	$ 38,145
Weighted-average interest rate	—	—	—	—	—	3.61%	3.61%	

(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 post-retirement 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. Oversight of our pension plan investment strategies is performed by the Finance Committee of the Board of Directors, which approves investment and funding policies, objectives and strategies that seek an appropriate return for the pension plan. We manage interest rate risk associated with our pension and other post-retirement 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, 2018, we had cash deposited as collateral of $78.0 million and letters of credit of $6.5 million outstanding related to our energy derivative contracts. Price movements and/or a downgrade in our credit ratings could impact further the amount of collateral required. See "Credit Ratings" for further information. For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below "investment grade" based on our positions outstanding at December 31, 2018, we would potentially be required to post additional collateral of up to $3.5 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 $5.2 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, 2018, we had interest rate swap agreements outstanding with a notional amount totaling $235.0 million and we had deposited cash in the amount of $0.5 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, 2018, we would have to post $2.9 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 hedge a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives 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.

Regulatory risk is mitigated through 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. Oversight of our regulatory strategies and policies is performed by senior management and our Board of Directors. 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, 2018 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)
2019	$ (2,238)	$ 7,289	$ (991)	$ (32,285)	$ 34	$ (19,047)	$ (443)	$ 6,252
2020	—	—	(1,266)	(7,797)	(28)	(4,044)	(1,517)	(240)
2021	—	—	—	(1,393)	—	—	(629)	47
2022	—	—	—	—	—	—	—	—
2023	—	—	—	—	—	—	—	—
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 following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2017 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)
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	—	—	—	—	—	—	—	—

(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."

Compliance risk is mitigated through 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. Oversight of our compliance risk strategy is performed by senior management, including our Chief Compliance Officer, and the Environmental, Technology and Operations Committee and the Audit Committee of our Board of Directors.

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.

Cyber and Technology Risk

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

We mitigate cyber and 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."

Oversight of our strategic risk is performed by the Board of Directors and senior management. We 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.

Oversight of our external mandate risk mitigation strategies is performed by the Environmental, Technology and Operations Committee of our Board of Directors and 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, 2018 and 2017, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 19, 2019, 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 19, 2019

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

	2018	2017	2016
Operating Revenues:			
Utility revenues:			
Utility revenues, exclusive of alternative revenue programs	$ 1,368,657	$ 1,442,980	$ 1,389,256
Alternative revenue programs	908	(19,594)	29,658
Total utility revenues	1,369,565	1,423,386	1,418,914
Non-utility revenues	27,328	22,543	23,569
Total operating revenues	1,396,893	1,445,929	1,442,483
Operating Expenses:			
Utility operating expenses:			
Resource costs	494,736	524,566	551,366
Other operating expenses	318,274	310,143	305,737
Acquisition costs	3,718	14,618	—
Depreciation and amortization	182,877	171,281	160,514
Taxes other than income taxes	107,295	106,752	98,735
Non-utility operating expenses:			
Other operating expenses	28,081	25,650	25,501
Depreciation and amortization	799	740	769
Total operating expenses	1,135,780	1,153,750	1,142,622
Income from operations	261,113	292,179	299,861
Interest expense	99,715	95,361	86,496
Interest expense to affiliated trusts	1,221	831	634
Capitalized interest	(3,939)	(3,310)	(2,651)
Other expense (income)—net	1,458	607	(20)
Income before income taxes	162,658	198,690	215,402
Income tax expense	26,060	82,758	78,086
Net income	136,598	115,932	137,316
Net income attributable to noncontrolling interests	(169)	(16)	(88)
Net income attributable to Avista Corp. shareholders	$ 136,429	$ 115,916	$ 137,228
Weighted-average common shares outstanding (thousands)—basic	65,673	64,496	63,508
Weighted-average common shares outstanding (thousands)—diluted	65,946	64,806	63,920
Earnings per common share attributable to Avista Corp. shareholders:			
Basic	$ 2.08	$ 1.80	$ 2.16
Diluted	$ 2.07	$ 1.79	$ 2.15

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

	2018	2017	2016
Net income	$ 136,598	$ 115,932	$ 137,316
Other Comprehensive Income (Loss):			
Change in unfunded benefit obligation for pension and other postretirement benefit plans—net of taxes of $523, $(281) and $(495), respectively	1,966	(522)	(918)
Total other comprehensive income (loss)	1,966	(522)	(918)
Comprehensive income	138,564	115,410	136,398
Comprehensive income attributable to noncontrolling interests	(169)	(16)	(88)
Comprehensive income attributable to Avista Corporation shareholders	$ 138,395	$ 115,394	$ 136,310

The Accompanying Notes are an Integral Part of These Statements.

Consolidated Balance Sheets

Avista Corporation
As of December 31,
Dollars in thousands

	2018	2017
Assets:		
Current Assets:		
Cash and cash equivalents	$ 14,656	$ 16,172
Accounts and notes receivable—less allowances of $5,233 and $5,132, respectively	165,824	185,664
Materials and supplies, fuel stock and stored natural gas	63,881	58,075
Regulatory assets	48,552	44,750
Other current assets	54,010	32,873
Total current assets	346,923	337,534
Net utility property	4,648,930	4,398,810
Goodwill	57,672	57,672
Non-current regulatory assets	614,354	619,399
Other property and investments—net and other non-current assets	114,697	101,317
Total assets	$ 5,782,576	$ 5,514,732
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 108,372	$ 107,289
Current portion of long-term debt and capital leases	107,645	277,438
Short-term borrowings	190,000	105,398
Regulatory liabilities	113,209	48,264
Other current liabilities	120,358	159,113
Total current liabilities	639,584	697,502
Long-term debt and capital leases	1,755,529	1,491,799
Long-term debt to affiliated trusts	51,547	51,547
Pensions and other postretirement benefits	222,537	203,566
Deferred income taxes	487,602	466,630
Non-current regulatory liabilities	780,701	800,089
Other non-current liabilities and deferred credits	71,031	73,115
Total liabilities	4,008,531	3,784,248
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Equity:		
Avista Corporation Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 65,688,356 and 65,494,333 shares issued and outstanding, respectively	1,136,491	1,133,448
Accumulated other comprehensive loss	(7,866)	(8,090)
Retained earnings	644,595	604,470
Total Avista Corporation shareholders' equity	1,773,220	1,729,828
Noncontrolling Interests	825	656
Total equity	1,774,045	1,730,484
Total liabilities and equity	$ 5,782,576	$ 5,514,732

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

	2018	2017	2016
Operating Activities:			
Net income	$ 136,598	$ 115,932	$ 137,316
Non-cash items included in net income:			
Depreciation and amortization	187,318	175,655	164,925
Provision for deferred income taxes	8,570	69,657	124,543
Power and natural gas cost deferrals—net	10,263	11,741	16,835
Amortization of debt expense	2,967	3,254	3,477
Amortization of investment in exchange power	2,450	2,450	2,450
Stock-based compensation expense	5,367	7,359	7,891
Equity-related AFUDC	(6,554)	(6,669)	(8,475)
Pension and other postretirement benefit expense	32,017	37,074	38,786
Amortization of Spokane Energy contract	—	—	14,694
Other regulatory assets and liabilities and deferred debits and credits	27,512	(9,144)	(26,245)
Change in decoupling regulatory deferral	(1,288)	24,179	(29,789)
Other	1,114	1,860	5,557
Contributions to defined benefit pension plan	(22,000)	(22,000)	(12,000)
Cash paid on settlement of interest rate swap derivatives	(32,174)	(11,302)	(53,966)
Cash received on settlement of interest rate swap derivatives	5,594	2,479	—
Changes in certain current assets and liabilities:			
Accounts and notes receivable	15,474	(9,270)	(17,170)
Materials and supplies, fuel stock and stored natural gas	(5,807)	(4,767)	834
Collateral posted for derivative instruments	(4,128)	(22,394)	10,712
Income taxes receivable	2,021	53,414	(33,923)
Other current assets	(2,589)	(2,106)	(3,907)
Accounts payable	(470)	(8,162)	5,176
Other current liabilities	(370)	1,058	10,546
Net cash provided by operating activities	361,885	410,298	358,267
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(424,350)	(412,339)	(406,644)
Issuance of notes receivable at subsidiaries	(3,555)	(3,700)	(10,094)
Repayments from notes receivable at subsidiaries	871	—	5,000
Equity and property investments made by subsidiaries	(13,283)	(13,680)	(13,097)
Distributions received from investments	2,228	1,915	—
Other	(2,343)	(6,299)	(7,631)
Net cash used in investing activities	$ (440,432)	$ (434,103)	$ (432,466)

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

	2018	2017	2016
Financing Activities:			
Net increase (decrease) in short-term borrowings	$ 84,603	$ (15,000)	$ 15,000
Proceeds from issuance of long-term debt	374,621	90,000	245,000
Maturity of long-term debt and capital leases	(277,438)	(3,287)	(163,167)
Issuance of common stock—net of issuance costs	1,207	56,380	66,953
Cash dividends paid	(98,046)	(92,460)	(87,154)
Other	(7,916)	(4,163)	(4,410)
Net cash provided by financing activities	77,031	31,470	72,222
Net increase (decrease) in cash and cash equivalents	(1,516)	7,665	(1,977)
Cash and cash equivalents at beginning of year	16,172	8,507	10,484
Cash and cash equivalents at end of year	$ 14,656	$ 16,172	$ 8,507
Supplemental Cash Flow Information:			
Cash paid (received) during the year:			
Interest	$ 97,437	$ 95,499	$ 86,319
Income taxes paid	17,801	5,579	5,403
Income tax refunds	(3,025)	(47,086)	(18,861)
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	31,868	31,157	30,252

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, except per share amounts

	2018	2017	2016
Common Stock—Shares:			
Shares outstanding at beginning of year	65,494,333	64,187,934	62,312,651
Shares issued through equity compensation plans	185,794	214,925	203,727
Shares issued through Employee Investment Plan (401-K)	8,229	21,474	26,556
Shares issued through sales agency agreements	—	1,070,000	1,645,000
Shares outstanding at end of year	65,688,356	65,494,333	64,187,934
Common Stock—Amount:			
Balance at beginning of year	$ 1,133,448	$ 1,075,281	$ 1,004,336
Equity compensation expense	5,765	6,530	7,065
Issuance of common stock through equity compensation plans	791	720	624
Issuance of common stock through Employee Investment Plan (401-K)	416	939	1,061
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	(3,929)	(3,552)	(3,072)
Purchase of subsidiary noncontrolling interests	—	(1,191)	—
Balance at end of year	1,136,491	1,133,448	1,075,281
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	(8,090)	(7,568)	(6,650)
Other comprehensive income (loss)	1,966	(522)	(918)
Reclassification of excess income tax benefits (see Note 2)	(1,742)	—	—
Balance at end of year	(7,866)	(8,090)	(7,568)
Retained Earnings:			
Balance at beginning of year	604,470	581,014	530,940
Net income attributable to Avista Corporation shareholders	136,429	115,916	137,228
Cash dividends paid (common stock)	(98,046)	(92,460)	(87,154)
Reclassification of excess income tax benefits (see Note 2)	1,742	—	—
Balance at end of year	644,595	604,470	581,014
Total Avista Corporation shareholders' equity	$ 1,773,220	$ 1,729,828	$ 1,648,727
Noncontrolling Interests:			
Balance at beginning of year	$ 656	$ (251)	$ (339)
Net income attributable to noncontrolling interests	169	16	88
Purchase of subsidiary noncontrolling interests	—	891	—
Balance at end of year	825	656	(251)
Total equity	$ 1,774,045	$ 1,730,484	$ 1,648,476
Dividends declared per common share	$ 1.49	$ 1.43	$ 1.37

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, Inc., which is a subsidiary of AERC. See Note 22 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 acquisition was subject to a number of approvals and the satisfaction or waiver of other specified conditions. On January 23, 2019, Avista Corp. and Hydro One mutually agreed to terminate the Merger Agreement. See Note 24 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. 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).

Certain line items are presented in a more condensed form on the Consolidated Balance Sheet as of December 31, 2018 than in prior periods. The prior year amounts were reclassified to conform to the current year presentation. The primary classification changes were related to classifying all current regulatory assets, current regulatory liabilities, non-current regulatory assets and non-current regulatory liabilities into their own line items. Previously, these items were either on many separate line items or embedded in other line items such as "Other property and investments—net and other non-current assets" or "Other non-current liabilities, regulatory liabilities and deferred credits." See Note 3 and Note 21 for a summary of the items contained in certain balance sheet accounts.

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.

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:

	2018	2017	2016
Avista Utilities			
Ratio of depreciation to average depreciable property	3.17%	3.12%	3.11%
Alaska Electric Light and Power Company			
Ratio of depreciation to average depreciable property	2.46%	2.43%	2.39%

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	44
Electric transmission	58	41
Electric distribution	35	40
Natural gas distribution property	46	N/A
Other shorter-lived general plant	10	16

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 expense (income)—net." The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service and included in rate base.

The WUTC authorized Avista Utilities to calculate AFUDC using its allowed rate of return. Beginning in 2018, to the extent amounts calculated using this rate exceed the AFUDC amounts calculated using the FERC formula, Avista Utilities capitalizes the excess as a regulatory asset. The regulatory asset is being amortized over the average useful life of Avista Utilities' utility plant which is approximately 30 years.

The effective AFUDC rate was the following for the years ended December 31:

	2018	2017	2016
Avista Utilities			
Effective AFUDC rate	7.43%	7.29%	7.29%
Alaska Electric Light and Power Company			
Effective AFUDC rate	9.04%	9.48%	9.40%

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, 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 2018, 2017 or 2016. 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):

	2018	2017	2016
Stock-based compensation expense	$ 5,367	$ 7,359	$ 7,891
Income tax benefits [(1)]	1,127	2,576	2,762
Excess tax benefits on settled share-based employee payments	990	2,348	1,597

(1) For 2017 and 2016 income tax benefits were calculated using a 35 percent income tax rate; however, due to the TCJA enactment, beginning on January 1, 2018 income tax benefits are calculated using a 21 percent tax rate.

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, for restricted shares granted prior to 2018, 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. 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:

	2018	2017	2016
Restricted Shares			
Shares granted during the year	40,661	57,746	58,610
Shares vested during the year	(53,352)	(57,473)	(52,385)
Unvested shares at end of year	91,998	106,053	109,806
Unrecognized compensation expense at end of year (in thousands)	$ 1,964	$ 1,853	$ 1,853
TSR Awards			
TSR shares granted during the year	80,724	114,390	116,435
TSR shares vested during the year	(107,342)	(107,649)	(111,665)
TSR shares earned based on market metrics	—	158,262	132,887
Unvested TSR shares at end of year	187,172	218,507	222,228
Unrecognized compensation expense (in thousands)	$ 3,706	$ 2,849	$ 3,409
CEPS Awards			
CEPS shares granted during the year	40,329	57,223	57,521
CEPS shares vested during the year	(53,699)	(53,862)	(55,835)
CEPS shares earned based on market metrics	30,102	41,502	90,460
Unvested CEPS shares at end of year	93,579	108,581	110,452
Unrecognized compensation expense (in thousands)	$ 1,260	$ 1,856	$ 1,671

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, 2018 and 2017, the Company had recognized cumulative compensation expense and a liability of $0.3 million and $1.5 million, respectively, related to the dividend component on the outstanding and unvested share grants.

Other Expense (Income)—Net

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

	2018	2017	2016
Interest income	$ (2,710)	$ (2,162)	$ (1,823)
Interest on regulatory deferrals	(990)	(1,288)	(1,308)
Equity-related AFUDC	(6,554)	(6,669)	(8,475)
Non-service portion of pension and other postretirement benefit expenses	5,156	7,670	10,058
Net loss on investments	5,369	4,160	2,152
Other expense (income)	1,187	(1,104)	(624)
Total	$ 1,458	$ 607	$ (20)

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 under contingent stock awards. See Note 19 for earnings per common share calculations.

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts to provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts.

The following table presents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in thousands):

	2018	2017	2016
Allowance as of the beginning of the year	$ 5,132	$ 5,026	$ 4,530
Additions expensed during the year	3,917	5,317	6,053
Net deductions	(3,816)	(5,211)	(5,557)
Allowance as of the end of the year	$ 5,233	$ 5,132	$ 5,026

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 non-current regulatory liability on the Consolidated Balance Sheets in the following amounts as of December 31 (dollars in thousands):

	2018	2017
Regulatory liability for utility plant retirement costs	$ 297,379	$ 285,786

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, 2018 and determined that goodwill was not impaired at that time. There were no events or circumstances that changed between November 30, 2018 and December 31, 2018 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 2017 and 2018 and the balance was as follows (dollars in thousands):

	AEL&P	Other	Accumulated Impairment Losses	Total
Balance as of December 31, 2017 and 2018	$ 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 associated with energy commodity derivative instruments 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.

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 21 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.

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.

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

	2018	2017
Appropriated retained earnings	$ 39,346	$ 33,917

Operating Leases

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from 1 to 45 years. The following table details future minimum lease payments under these agreements (dollars in thousands):

	2019	2020	2021	2022	2023	Thereafter	Total
Avista Utilities [(1)]	$ 4,504	$ 4,394	$ 4,369	$ 4,292	$ 4,290	$ 98,962	$ 120,811
Other	491	482	490	490	490	3,427	5,870
Minimum lease payments	$ 4,995	$ 4,876	$ 4,859	$ 4,782	$ 4,780	$ 102,389	$ 126,681

(1) The minimum lease payments for Avista Utilities are primarily related to a lease of the Montana riverbed for the Company's hydroelectric facilities on the Clark Fork River. These payments were disclosed as a generating facility contractual commitment at the Energy Purchase Contracts footnote in prior years. These payments are included as operating expenses for the Company's regulated operations and are recovered through base retail rates.

See Note 2 for discussion of the new lease standard that the Company adopted on January 1, 2019.

Capital Leases

The Company has one capital lease at AEL&P which is a PPA (treated as a lease for accounting purposes) related to the Snettisham Hydroelectric Project that expires in 2034. While the PPA is treated as a capital lease for accounting purposes, for ratemaking purposes the 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. See Note 14 for further discussion of the Snettisham capital lease. See Note 2 for discussion of the new lease standard, which the Company adopted on January 1, 2019.

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, 2018, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 20 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)"

On January 1, 2018, the Company adopted 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 Company elected to use a modified retrospective method of adoption, which required a cumulative adjustment to opening retained earnings (if any were identified), as opposed to a full retrospective application. The Company did not identify any adjustments required to opening retained earnings related to the adoption of the new revenue standard. The Company applied the standards only to contracts that were not completed as of the implementation date. The Company did not apply the new guidance to contracts that were completed with all revenue recognized prior to the implementation date. In addition, total operating revenues on the Consolidated Statements of Income in years prior to 2018 would not have changed if the Company had elected to apply the full retrospective method of adoption.

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 does not expect any significant change in operating revenues or net income going forward as a result of the adoption of this standard.

The only changes in revenue that resulted from the adoption of this ASU were related to the presentation of utility-related taxes collected from customers and the timing of when revenue from self-generated RECs is recognized.

Under ASU No. 2014-09, revenue associated with the sale of RECs is 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 was 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 does not have a material impact on net income.

See Note 4 for the Company's complete revenue 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 No. 2016-02, upon adoption, the effects of this standard must be applied using a modified retrospective approach to the earliest period presented. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. In July 2018, the FASB issued ASU No. 2018-11 which provides a practical expedient that allows companies to use an optional transition method. Under the optional transition method, a cumulative adjustment to retained earnings during the period of adoption is recorded and prior periods would not require restatement.

Upon adoption, the Company expects to elect a package of practical expedients that will allow it to not reassess whether any expired or existing contract is a lease or contains a lease, the lease classification of any expired or existing leases, and the initial direct costs for any existing leases. The Company also expects to elect practical expedients associated with hindsight, historical easements, and the optional transition method.

Adoption of the standard will impact the Company's Consolidated Balance Sheet through recognition of right-of-use assets and lease liabilities for the Company's operating leases. As of December 31, 2018, the Company estimates that it will record a right-of-use asset and lease liability of between $65.0 million and $75.0 million, not including the Snettisham finance lease (formerly a capital lease) that is already reflected on the Consolidated Balance Sheet as of December 31, 2018.

ASU No. 2017-07 "Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost"

On January 1, 2018, the Company adopted ASU No. 2017-07, which amended the income statement presentation of the components of net period benefit cost for an entity's defined benefit pension and other postretirement plans. Under previous GAAP, net benefit cost consisted of several components that reflected different aspects of an employer's financial arrangements as well as the cost of benefits earned by employees. These components were 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 prior practice, under which entities capitalized 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 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.

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 benefit costs to the service-cost component. Due to the retrospective requirements for income statement presentation, for the years ended December 31, 2017 and December 31, 2016, the Company reclassified $7.7 million and $10.1 million, respectively in non-service cost components of pension and other postretirement benefits from utility other operating expenses to other expense (income)—net on the Consolidated Statements of Income. See Note 10 for additional discussion regarding pension and other postretirement benefit expense.

ASU No. 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 No. 2018-02, which amended the guidance for reporting comprehensive income. This ASU allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the enactment of the TCJA in December 2017. This ASU is effective for periods beginning after December 15, 2018 and early adoption is permitted. Upon adoption, the requirements of this 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 early adopted this standard effective January 1, 2018 and elected to apply the guidance during the period of adoption rather than apply the standard retrospectively. As a result, the Company reclassified $1.7 million in tax benefits from accumulated other comprehensive loss to retained earnings during the year ended December 31, 2018.

ASU 2018-13 "Fair Value Measurement (Topic 820)"

In August 2018, the FASB issued ASU No. 2018-13, which amends the fair value measurement disclosure requirements of ASC 820. The requirements of this ASU include additional disclosure regarding the range and weighted average used to develop significant unobservable inputs for Level 3 fair value estimates and the elimination of certain other previously required disclosures, such as the narrative description of the valuation process for Level 3 fair value measurements. This ASU is effective for periods beginning after December 15, 2019 and early adoption is permitted. Entities have the option to early adopt the eliminated or modified disclosure requirements and delay the adoption of all the new disclosure requirements until the effective date of the ASU. The Company is in the process of evaluating this standard; however, it has determined that it will not early adopt any portion of this standard as of December 31, 2018.

ASU No. 2018-14 "Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20)"

In August 2018, the FASB issued ASU No. 2018-14, which amends ASC 715 to add, remove and/or clarify certain disclosure requirements related to defined benefit pension and other postretirement plans. The additional disclosure requirements are primarily narrative discussion of significant changes in the benefit obligations and plan assets. The removed disclosures are primarily information about accumulated other comprehensive income expected to be recognized over the next year and the effects of changes associated with assumed health care costs. This ASU is effective for periods beginning after December 15, 2021 and early adoption is permitted. The Company is in the process of evaluating this standard; however, it has determined that it will not early adopt this standard as of December 31, 2018.

Note 3. Balance Sheet Components

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):

	2018	2017
Materials and supplies	$ 47,403	$ 41,493
Fuel stock	4,869	4,843
Stored natural gas	11,609	11,739
Total	$ 63,881	$ 58,075

Other Current Assets

Other current assets consisted of the following as of December 31 (dollars in thousands):

	2018	2017
Collateral posted for derivative instruments	$ 26,809	$ 12,020
Prepayments	17,536	11,782
Other	9,665	9,071
Total	$ 54,010	$ 32,873

Other Property and Investments—net and Other Non-Current Assets

Other property and investments—net and other non-current assets consisted of the following as of December 31 (dollars in thousands):

	2018	2017
Non-utility property	$ 31,355	$ 28,340
Equity investments	29,257	22,134
Investment in affiliated trust	11,547	11,547
Notes receivable	11,073	9,560
Deferred compensation assets	8,400	8,458
Other	23,065	21,278
Total	$ 114,697	$ 101,317

Other Current Liabilities

Other current liabilities consisted of the following as of December 31 (dollars in thousands):

	2018	2017
Accrued taxes other than income taxes	$ 36,858	$ 33,802
Unsettled interest rate swap derivative liabilities	—	34,447
Employee paid time off accruals	20,992	20,330
Accrued interest	16,704	16,351
Pensions and other postretirement benefits	9,151	11,544
Utility energy commodity derivative liabilities	3,908	8,848
Other	32,745	33,791
Total	$ 120,358	$ 159,113

Other Non-Current Liabilities and Deferred Credits

Other non-current liabilities and deferred credits consisted of the following as of December 31 (dollars in thousands):

	2018	2017
Deferred investment tax credits	$ 29,725	$ 30,266
Asset retirement obligations	18,266	17,482
Derivative liabilities	10,300	10,456
Other	12,740	14,911
Total	$ 71,031	$ 73,115

Note 4. Revenue

ASC 606, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and superseded previous revenue recognition guidance, including industry-specific guidance, became effective on January 1, 2018. 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.

Utility Revenues

Revenue from Contracts with Customers

General

The majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers, which has two performance obligations, (1) having service available for a specified period (typically a month at a time) and (2) the delivery of energy to customers. The total energy price generally has a fixed component (basic charge) related to having service available and a usage-based component, related to the delivery and consumption of energy.

In addition, the sale of electricity and natural gas is governed by the various state utility commissions, which set rates, charges, terms and conditions of service, and prices. Collectively, these rates, charges, terms and conditions are included in a "tariff," which governs all aspects of the provision of regulated services. Tariffs are only permitted to be changed through a rate-setting process involving an independent, third-party regulator empowered by statute to establish rates that bind customers. Thus, all regulated sales by the Company are conducted subject to the regulator-approved tariff.

Tariff sales involve the current provision of commodity service (electricity and/or natural gas) to customers for a price that generally has a basic charge and a usage-based component. Tariff rates also include certain pass-through costs to customers such as natural gas costs, retail revenue credits and other miscellaneous regulatory items that do not impact net income, but can cause total revenue to fluctuate significantly up or down compared to previous periods. The commodity is sold and/or delivered to and consumed by the customer simultaneously, and the provisions of the relevant tariff determine the charges the Company may bill the customer, payment due date, and other pertinent rights and obligations of both parties. Generally, tariff sales do not involve a written contract. Given that all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately at that time.

Revenues from contracts with customers are presented in the Consolidated Statements of Income in the line item "Utility revenues, exclusive of alternative revenue programs."

Unbilled Revenue from Contracts with Customers

The determination of the volume of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month (once per month for each individual customer). 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. The Company's 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):

	2018	2017
Unbilled accounts receivable	$ 67,098	$ 68,641

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts which are not accounted for as derivatives that are within the scope of ASC 606 and considered revenue from contracts with customers. Revenue is recognized as energy is delivered to the customer or the service is available for specified period of time, consistent with the discussion of tariff sales above.

Alternative Revenue Programs (Decoupling)

ASC 606 retained existing GAAP associated with alternative revenue programs, which specified that alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires that an entity present revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the face of the Consolidated Statements of Income. The Company's decoupling mechanisms (also known as a FCA in Idaho) qualify as alternative revenue programs. 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 or 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 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. The amounts expected to be collected from customers within 24 months represents an estimate which must be made by the Company on an ongoing basis due to it being based on the volumes of electric and natural gas sold to customers on a go-forward basis.

Two acceptable methods of presenting decoupling revenue have evolved within the utility industry and a policy election is required by the Company. The two options relate to how the collection/refund of previously recognized decoupling revenue is presented within total revenue. The first option is the gross method, which is to amortize the decoupling regulatory asset/liability to the alternative revenue program line item on the Consolidated Statement of Income as it is collected from or refunded to customers. The cash passing between the Company and the customers is presented in revenue from contracts with customers since it is a portion of the overall tariff paid by customers. This method results in a gross-up to both revenue from contracts with customers and revenue from alternative revenue programs, but has a net zero impact on total revenue. The second option is the net method, which requires the amortization of the decoupling regulatory asset/liability to be presented within revenue from contracts with customers such that, when netted against the cash passing between the Company and the customers within the same line item, there is a net zero impact to revenue from contracts with customers and total revenue. The Company has elected the gross method for the presentation of alternative revenue program revenue, consistent with historical practice. Depending on whether the previous deferral balance being amortized was a regulatory asset or regulatory liability, and depending on the size and direction of the current year deferral of surcharges and/or rebates to customers, it could result in negative alternative revenue program revenue during the year.

Derivative Revenue

Most wholesale electric and natural gas transactions (including both physical and financial transactions), and the sale of fuel are considered derivatives, which are scoped out of ASC 606. As such, these revenues are disclosed separately from revenue from contracts with customers. Revenue is recognized for these items upon the settlement/expiration of the derivative contract. Derivative revenue includes those transactions which are entered into and settled within the same month.

Other Utility Revenue

Other utility revenue includes rent, revenues from the lineman training school, sales of materials, late fees and other charges that do not represent contracts with customers. Other utility revenue also includes the provision for earnings sharing and the deferral and amortization of refunds to customers associated with the TCJA, enacted in December 2017. This revenue is scoped out of ASC 606, as this revenue does not represent items where a customer is a party that has contracted with the Company to obtain goods or services that are an output of the Company's ordinary activities in exchange for consideration. As such, these revenues are presented separately from revenue from contracts with customers.

Other Considerations for Utility Revenues

Contracts with Multiple Performance Obligations

In addition to the tariff sales described above, which are stand-alone energy sales, the Company has bundled arrangements which contain multiple performance obligations including some combination of energy, capacity, energy reserves and RECs. Under these arrangements, the total contract price is allocated to the various performance obligations and revenue is recognized as the obligations are satisfied. Depending on the source of the revenue, it could either be included in revenue from contracts with customers or derivative revenue.

Gross Versus Net Presentation

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 derivative revenues.

Utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) are taxes that are imposed on Avista Utilities as opposed to being imposed on its customers; therefore, Avista Utilities is the taxpayer and records these transactions on a gross basis in revenue from contracts with customers and operating expense (taxes other than income taxes). The utility-related taxes collected from customers at AEL&P are imposed on the customers rather than AEL&P; therefore, the customers are the taxpayers and AEL&P is acting as their agent. As such, effective January 1, 2018, these transactions at AEL&P are presented on a net basis within revenue from contracts with customers. Prior to the adoption of ASU No. 2014-09, the Company presented utility-related taxes at AEL&P on a gross basis. In prior years, there were approximately $2.0 million annually in utility-related taxes collected from customers included in revenue for AEL&P.

Utility-related taxes that were included in revenue from contracts with customers were as follows for the years ended December 31 (dollars in thousands):

	2018	2017	2016
Utility-related taxes	$ 58,730	$ 64,012	$ 57,745

Non-Utility Revenues

Revenue from Contracts with Customers

Non-utility revenues from contracts with customers are primarily derived from the operations of METALfx. The contracts associated with METALfx have one performance obligation, the delivery of a product, and revenues are recognized when the risk of loss transfers to the customer, which occurs when products are shipped.

Other Revenue

Other non-utility revenue primarily relates to rent revenue, which is scoped out of ASC 606; therefore, this revenue is presented separately from revenue from contracts with customers.

Significant Judgments and Unsatisfied Performance Obligations

The vast majority of the Company's revenues are derived from the rate-regulated sale of electricity and natural gas that have two performance obligations that are satisfied throughout the period and as energy is delivered to customers. In addition, the customers do not pay for energy in advance of receiving it. As such, the Company does not have any significant unsatisfied performance obligations or deferred revenues as of period-end associated with these revenues. Also, the only significant judgments involving revenue recognition are estimates surrounding unbilled revenue and receivables from contracts with customers (discussed in detail above) and estimates surrounding the amount of decoupling revenues which will be collected from customers within 24 months.

The Company has certain capacity arrangements, where the Company has a contractual obligation to provide either electric or natural gas capacity to its customers for a fixed fee. Most of these arrangements are paid for in arrears by the customers and do not result in deferred revenue and only result in receivables from the customers. The Company does have one capacity agreement where the customer makes payments throughout the year and depending on the timing of the customer payments, it can result in an immaterial amount of deferred revenue or a receivable from the customer. As of December 31, 2018, the Company estimates it had unsatisfied capacity performance obligations of $10.3 million, which will be recognized as revenue in future periods as the capacity is provided to the customers. These performance obligations are not reflected in the financial statements, as the Company has not received payment for these services.

Disaggregation of Total Operating Revenue

The following table disaggregates total operating revenue by segment and source for the year ended December 31, 2018 (dollars in thousands):

	2018
Avista Utilities	
Revenue from contracts with customers	$ 1,147,935
Derivative revenues	186,459
Alternative revenue programs	908
Deferrals and amortizations for rate refunds to customers	(18,241)
Other utility revenues	8,905
Total Avista Utilities	1,325,966
AEL&P	
Revenue from contracts with customers	44,758
Deferrals and amortizations for rate refunds to customers	(1,753)
Other utility revenues	594
Total AEL&P	43,599
Other	
Revenue from contracts with customers	26,154
Other revenues	1,174
Total other	27,328
Total operating revenues	$ 1,396,893

Utility Revenue from Contracts with Customers by Type and Service

The following table disaggregates revenue from contracts with customers associated with the Company's utility operations for the year ended December 31, 2018 (dollars in thousands):

	Avista Utilities	AEL&P	2018 Total Utility
Electric Operations			
Revenue from contracts with customers			
Residential	$ 368,753	$ 18,506	$ 387,259
Commercial and governmental	314,532	25,989	340,521
Industrial	109,846	—	109,846
Public street and highway lighting	7,539	263	7,802
Total retail revenue	800,670	44,758	845,428
Transmission	17,864	—	17,864
Other revenue from contracts with customers	27,364	—	27,364
Total revenue from contracts with customers	$ 845,898	$ 44,758	$ 890,656
Natural Gas Operations			
Revenue from contracts with customers			
Residential	$ 194,340	$ —	$ 194,340
Commercial	89,341	—	89,341
Industrial and interruptible	4,753	—	4,753
Total retail revenue	288,434	—	288,434
Transportation	9,103	—	9,103
Other revenue from contracts with customers	4,500	—	4,500
Total revenue from contracts with customers	$ 302,037	$ —	$ 302,037

Note 5. 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 $235.9 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, 2018, the Company has eight 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 five of the eight VIEs, Avista Corp. does not have any additional commitments beyond its initial investment. For the other three VIEs, Avista Corp. has total commitments of $25.6 million, and as of December 31, 2018, has invested $11.8 million, leaving $13.8 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 three investments having no termination date (as they are perpetual). In addition, one of the funds is closed and expired and the Company is awaiting final distribution as soon as the underlying investments are liquidated. As of December 31, 2018, the Company has a total carrying amount in these investment funds of $22.5 million.

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, 2018 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2019	206	941	10,732	101,293	197	2,790	2,909	54,418
2020	—	—	1,138	47,225	123	959	1,430	14,625
2021	—	—	—	9,670	—	—	1,049	4,100
2022	—	—	—	—	—	—	—	—
2023	—	—	—	—	—	—	—	—
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 following table presents the underlying energy commodity derivative volumes as of December 31, 2017 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
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	—	—	—	—	—	—	—	—

(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):

	2018	2017
Number of contracts	31	18
Notional amount (in United States dollars)	$ 4,018	$ 2,552
Notional amount (in Canadian dollars)	5,386	3,241

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, 2018	6	70,000	2019
	6	60,000	2020
	2	25,000	2021
	7	80,000	2022
December 31, 2017	14	275,000	2018
	6	70,000	2019
	3	30,000	2020
	1	15,000	2021
	5	60,000	2022

During the second quarter 2018, in connection with the issuance and sale of $375.0 million of Avista Corp. first mortgage bonds (see Note 14), the Company cash-settled fourteen interest rate swap derivatives (notional aggregate amount of $275.0 million) and paid a net amount of $26.6 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, 2018 and December 31, 2017 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, 2018 (in thousands):

Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Fair Value Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current liabilities	$ —	$ (45)	$ —	$ (45)
Interest rate swap derivatives				
Other current assets	5,283	—	—	5,283
Other property and investments—net and other non-current assets	5,283	(440)	—	4,843
Other non-current liabilities and deferred credits	—	(7,391)	530	(6,861)
Energy commodity derivatives				
Other current assets	400	(130)	—	270
Other current liabilities	31,457	(73,155)	37,790	(3,908)
Other non-current liabilities and deferred credits	4,426	(21,292)	13,427	(3,439)
Total derivative instruments recorded on the balance sheet	$ 46,849	$ (102,453)	$ 51,747	$ (3,857)

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):

Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Fair Value Net Asset (Liability) on 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
Other current liabilities	—	(63,399)	28,952	(34,447)
Other non-current liabilities and deferred credits	—	(7,540)	6,018	(1,522)
Energy commodity derivatives				
Other current assets	1,386	(122)	—	1,264
Other current liabilities	26,641	(52,895)	17,406	(8,848)
Other non-current 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)

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):

	2018	2017
Energy commodity derivatives		
Cash collateral posted	$ 78,025	$ 39,458
Letters of credit outstanding	6,500	23,000
Balance sheet offsetting (cash collateral against net derivative positions)	51,217	27,438
Interest rate swap derivatives		
Cash collateral posted	530	34,970
Letters of credit outstanding	—	5,000
Balance sheet offsetting (cash collateral against net derivative positions)	530	34,970

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):

	2018	2017
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 2,193	$ 1,336
Additional collateral to post	2,193	1,336
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	7,831	73,514
Additional collateral to post	6,579	18,770

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):

	2018	2017
Utility plant in service	$ 384,431	$ 379,970
Accumulated depreciation	(261,997)	(255,604)

See Note 9 for further discussion of AROs.

While the obligations and liabilities with respect to Colstrip are to be shared among the co-owners on a pro rata basis, many of the environmental liabilities are joint and several under the law, so that if any co-owner failed to pay its share of such liability, the other co-owners (or any one of them) could be required to pay the defaulting co-owner's share (or the entire liability).

Note 8. Property, Plant and Equipment

Net Utility Property

Net utility property consisted of the following as of December 31 (dollars in thousands):

	2018	2017
Utility plant in service	$ 6,209,968	$ 5,853,308
Construction work in progress	160,598	157,839
Total	6,370,566	6,011,147
Less: Accumulated depreciation and amortization	1,721,636	1,612,337
Total net utility property	$ 4,648,930	$ 4,398,810

Gross 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):

	2018	2017
Avista Utilities:		
Electric production	$ 1,426,961	$ 1,392,017
Electric transmission	761,156	726,240
Electric distribution	1,726,410	1,617,451
Electric construction work-in-progress (CWIP) and other	341,041	322,144
Electric total	4,255,568	4,057,852
Natural gas underground storage	48,549	46,233
Natural gas distribution	1,118,720	1,027,197
Natural gas CWIP and other	76,488	63,803
Natural gas total	1,243,757	1,137,233
Common plant (including CWIP)	641,465	588,833
Total Avista Utilities	6,140,790	5,783,918
AEL&P:		
Electric production	99,803	97,883
Electric transmission	21,347	21,413
Electric distribution	22,374	21,061
Electric production held under long-term capital lease	71,007	71,007
Electric CWIP and other	7,072	7,341
Electric total	221,603	218,705
Common plant	8,173	8,524
Total AEL&P	229,776	227,229
Total gross utility property	6,370,566	6,011,147
Other [(1)]	39,145	36,783
Total	$ 6,409,711	$ 6,047,930

(1) Included in other property and investments—net and other non-current assets on the Consolidated Balance Sheets. Accumulated depreciation was $12.4 million as of December 31, 2018 and $11.6 million as of December 31, 2017 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 CCRs, 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 CCR rule has been the subject of ongoing litigation. In August 2018, the D.C. Circuit struck down provisions of the rule. The rule includes technical requirements for CCR landfills and surface impoundments. The Colstrip owners developed a multi-year compliance plan to address the CCR requirements and existing state obligations.

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. The Company expects to seek recovery of any increased costs related to complying with the CCR rule through customer rates.

In addition to the above, under a 2012 Administrative Order on Consent, the owners of Colstrip are required to provide financial assurance, primarily in the form of surety bonds, to secure each owner's pro rata share of various anticipated closure and remediation obligations. The amount of financial assurance required of each owner may, like the ARO, vary substantially due to the uncertainty and evolving nature of anticipated closure and remediation activities, and as those activities are completed over time.

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

	2018	2017	2016
Asset retirement obligation at beginning of year	$ 17,482	$ 15,515	$ 15,997
Liabilities incurred	—	1,171	430
Liabilities settled	(66)	—	(1,529)
Accretion expense	850	796	617
Asset retirement obligation at end of year	$ 18,266	$ 17,482	$ 15,515

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) 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 2018 and 2017 and $12.0 million in 2016. The Company expects to contribute $22.0 million in cash to the pension plan in 2019.

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):

	2019	2020	2021	2022	2023	Total 2024–2028
Expected benefit payments	$ 37,920	$ 38,486	$ 38,433	$ 39,018	$ 39,405	$ 210,240

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):

	2019	2020	2021	2022	2023	Total 2024–2028
Expected benefit payments	$ 6,766	$ 6,393	$ 6,566	$ 6,688	$ 6,740	$ 37,581

The Company expects to contribute $7.1 million to other postretirement benefit plans in 2019, 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, 2018 and 2017 and the components of net periodic benefit costs for the years ended December 31, 2018, 2017 and 2016 (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 716,561	$ 666,472	$ 132,947	$ 136,453
Service cost	21,614	20,406	3,188	3,220
Interest cost	26,096	27,898	4,831	5,490
Actuarial (gain)/loss	(48,641)	39,743	(610)	(6,020)
Plan change	—	3,158	—	—
Benefits paid	(44,001)	(41,116)	(6,303)	(6,196)
Benefit obligation as of end of year	$ 671,629	$ 716,561	$ 134,053	$ 132,947
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 605,652	$ 540,914	$ 37,953	$ 33,365
Actual return on plan assets	(40,954)	82,476	(1,101)	4,588
Employer contributions	22,000	22,000	—	—
Benefits paid	(42,647)	(39,738)	—	—
Fair value of plan assets as of end of year	$ 544,051	$ 605,652	$ 36,852	$ 37,953
Funded status	$ (127,578)	$ (110,909)	$ (97,201)	$ (94,994)
Amounts recognized in the Consolidated Balance Sheets:				
Other current liabilities	(1,477)	(1,663)	(580)	(529)
Non-current liabilities	(126,101)	(109,246)	(96,621)	(94,465)
Net amount recognized	(127,578)	(110,909)	(97,201)	(94,994)
Accumulated pension benefit obligation	$ 586,398	$ 624,345	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 63,796	$ 60,354
For fully eligible employees			$ 29,902	$ 32,891
For other participants			$ 40,355	$ 39,702
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 2,308	$ 2,066	$ (5,230)	$ (5,058)
Unrecognized net actuarial loss	138,516	102,624	52,441	44,382
Total	140,824	104,690	47,211	39,324
Less regulatory asset	(133,237)	(97,025)	(46,932)	(38,899)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 7,587	$ 7,665	$ 279	$ 425
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	4.31%	3.71%	4.32%	3.72%
Discount rate for annual expense	3.71%	4.26%	3.72%	4.23%
Expected long-term return on plan assets	5.50%	5.87%	5.20%	5.69%
Rate of compensation increase	4.67%	4.69%		
Medical cost trend pre-age 65—initial			6.00%	6.50%
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			6.25%	6.50%
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		
	2018	2017	2016	2018	2017	2016
Components of net periodic benefit cost:						
Service cost [(a)]	$ 21,614	$ 20,406	$ 18,302	$ 3,188	$ 3,220	$ 3,205
Interest cost	26,096	27,898	27,544	4,831	5,490	6,110
Expected return on plan assets	(33,018)	(31,626)	(27,547)	(1,973)	(1,899)	(1,861)
Amortization of prior service cost	257	2	2	(1,089)	(1,144)	(1,208)
Net loss recognition	7,879	9,793	8,511	4,232	4,934	5,728
Net periodic benefit cost	$ 22,828	$ 26,473	$ 26,812	$ 9,189	$ 10,601	$ 11,974

(a) Total service costs in the table above are recorded to the same accounts as labor expense. Labor and benefits expense is recorded to various projects based on whether the work is a capital project or an operating expense. Approximately 40 percent of all labor and benefits is capitalized to utility property and 60 percent is expensed to utility other operating expenses.

See Note 2 for discussion regarding the adoption of ASU No. 2017-07 and its impact to the presentation of pension and other postretirement benefits in the Consolidated Statements of Income and the Consolidated Balance Sheets.

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, 2018 by $8.1 million and the service and interest cost by $0.6 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, 2018 by $6.4 million and the service and interest cost by $0.5 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:

	2018	2017
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, 2018 and 2017.

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, 2018 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 7,061	$ —	$ 7,061
Fixed income securities:				
U.S. government issues	—	37,078	—	37,078
Corporate issues	—	175,908	—	175,908
International issues	—	31,561	—	31,561
Municipal issues	—	16,170	—	16,170
Mutual funds:				
U.S. equity securities	101,720	—	—	101,720
International equity securities	33,141	—	—	33,141
Absolute return (1)	2,249	—	—	2,249
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	43,303
International equity securities	—	—	—	30,944
Partnership/closely held investments:				
Absolute return (1)	—	—	—	60,612
Real estate	—	—	—	4,304
Total	$ 137,110	$ 267,778	$ —	$ 544,051

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

(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 2018 and 2017.

The fair value of other postretirement plan assets was determined as of December 31, 2018 and 2017.

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, 2018 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual funds (1)	$ 36,852	$ —	$ —	$ 36,852

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

(1) The balanced index fund for 2018 and 2017 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):

	2018	2017	2016
Employer 401(k) matching contributions	$ 10,243	$ 9,075	$ 8,710

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):

	2018	2017
Deferred compensation assets and liabilities	$ 8,400	$ 8,458

Note 11. Accounting for Income Taxes

Federal Income Tax Law Changes

On December 22, 2017, the TCJA was signed into law. The legislation included 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. included:

- 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 or the Reverse South Georgia Method 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; and
- NOL carryback deductions were eliminated, but carryforward deductions are allowed indefinitely with some annual limitations versus the previous 20-year limitation.

As a result of the TCJA and its reduction of the corporate income tax rate from 35 percent to 21 percent (among many other changes in the law), the Company recorded a regulatory liability associated with the revaluing of its deferred income tax assets and liabilities to the new corporate tax rate. The total net amount of the regulatory liability for excess deferred income taxes associated with the TCJA is $436.7 million as of December 31, 2018, compared to $442.3 million as of December 31, 2017, which reflects the amounts to be refunded to customers through the regulatory process. The Avista Utilities amounts related to utility plant commenced being returned to customers in 2018 and the Company expects they will be returned to customers over a period of approximately 36 years using the ARAM. The AEL&P amounts related to utility plant commenced being returned to customers in 2018 and the Company expects they will be returned to customers over a period of approximately 40 years using the Reverse South Georgia Method. The return of the regulatory liability attributable to non-plant excess deferred taxes of approximately $18.5 million (among all jurisdictions) as of December 31, 2018 will be determined by final orders from the WUTC, IPUC and OPUC during 2019.

Because most of the provisions of the TCJA were effective as of January 1, 2018 but customers' rates included a 35 percent corporate tax rate built in from prior general rate cases, the Company began accruing for a refund to customers for the change in federal income tax expense beginning January 1, 2018 forward. For Washington and Idaho, this accrual was recorded until all benefits prior to a permanent rate change were properly captured through the deferral process. Refunds have begun to Washington and Idaho customers through tariffs or other regulatory mechanisms or proceedings. For Oregon, a final order is expected during 2019 to determine the timing of refunds to customers.

Income Tax Expense

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

	2018	2017	2016
Current income tax expense (benefit)	$ 17,490	$ 13,101	$ (46,457)
Deferred income tax expense	8,570	69,657	124,543
Total income tax expense	$ 26,060	$ 82,758	$ 78,086

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 (21 percent in 2018 and 35 percent in 2017 and 2016) 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):

	2018		2017		2016	
Federal income taxes at statutory rates	$ 34,158	21.0%	$ 69,542	35.0%	$ 75,391	35.0%
Increase (decrease) in tax resulting from:						
Tax effect of regulatory treatment of utility plant differences	(8,153)	(5.0)	3,482	1.7	3,297	1.5
State income tax expense	1,191	0.7	1,110	0.6	1,316	0.6
Settlement of prior year tax returns and adjustment of tax reserves	(140)	(0.1)	(384)	(0.2)	13	—
Manufacturing deduction	—	—	(1,119)	(0.6)	—	—
Settlement of equity awards	(990)	(0.6)	(1,439)	(0.7)	(1,597)	(0.7)
Acquisition costs	329	0.2	2,491	1.3	—	—
Federal income tax rate change	—	—	10,169	5.1	—	—
Other	(335)	(0.2)	(1,094)	(0.5)	(334)	(0.1)
Total income tax expense	$ 26,060	16.0%	$ 82,758	41.7%	$ 78,086	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):

	2018	2017
Deferred income tax assets:		
Unfunded benefit obligation	$ 45,842	$ 41,944
Utility energy commodity and interest rate swap derivatives	11,724	23,364
Regulatory deferred tax credits	6,244	6,359
Tax credits	21,008	23,042
Power and natural gas deferrals	17,618	14,379
Deferred compensation	5,536	7,080
Deferred taxes on regulatory liabilities	106,909	105,508
Other	16,793	15,892
Total gross deferred income tax assets	231,674	237,568
Valuation allowances for deferred tax assets	(13,651)	(10,982)
Total deferred income tax assets after valuation allowances	218,023	226,586
Deferred income tax liabilities:		
Differences between book and tax basis of utility plant	509,789	494,783
Regulatory asset on utility, property plant and equipment	83,141	81,860
Regulatory asset for pensions and other postretirement benefits	47,893	43,914
Utility energy commodity and interest rate swap derivatives	11,724	23,364
Long-term debt and borrowing costs	24,609	19,992
Settlement with Coeur d'Alene Tribe	6,400	6,802
Other regulatory assets	15,318	16,695
Other	6,751	5,806
Total deferred income tax liabilities	705,625	693,216
Net long-term deferred income tax liability	$ 487,602	$ 466,630

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, 2018, the Company had $21.0 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 $7.3 million of the state tax credits. As such, the Company has recorded a valuation allowance of $13.7 million against the state tax credit carryforwards and reflected the net amount of $7.3 million as an asset as of December 31, 2018. State tax credits expire from 2020 to 2032.

Status of Internal Revenue Service (IRS) and State 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. All tax years after 2013 are open for an IRS tax examination. The IRS is currently reviewing tax years 2014 through 2016 and the Company does not yet know the final status of these examinations.

The Idaho State Tax Commission notified the Company in 2018 that they would be auditing the Company's tax returns for the years 2014 through 2016. The statute of limitations for Montana and Oregon to review 2014 and earlier tax years has expired.

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):

	2018	2017
Regulatory assets for deferred income taxes	$ 91,188	$ 90,315
Regulatory liabilities for deferred income taxes	453,610	460,542

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 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):

	2018	2017	2016
Utility power resources	$ 357,656	$ 380,523	$ 402,575

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):

	2019	2020	2021	2022	2023	Thereafter	Total
Power resources	$ 199,239	$ 174,236	$ 163,608	$ 162,895	$ 154,935	$ 990,024	$ 1,844,937
Natural gas resources	70,159	61,017	37,318	33,900	33,130	298,253	533,777
Total	$ 269,398	$ 235,253	$ 200,926	$ 196,795	$ 188,065	$ 1,288,277	$ 2,378,714

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, 2018 (principal and interest) was $65.3 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):

	2019	2020	2021	2022	2023	Thereafter	Total
Contractual obligations	$ 29,474	$ 33,311	$ 32,291	$ 28,142	$ 28,859	$ 195,743	$ 347,820

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, 2018, 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):

	2018	2017
Balance outstanding at end of period	$ 190,000	$ 105,000
Letters of credit outstanding at end of period	$ 10,503	$ 34,420
Average interest rate at end of period	3.18%	2.26%

As of December 31, 2018 and 2017, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Consolidated Balance Sheet.

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, 2018 and 2017, 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, 2018, 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	2018	2017
Avista Corp. Secured Long-Term Debt				
2018	First Mortgage Bonds	5.95%	—	250,000
2018	Secured Medium-Term Notes	7.39%–7.45%	—	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	3.91%	90,000	90,000
2048	First Mortgage Bonds (2)	4.35%	375,000	—
2051	First Mortgage Bonds	3.54%	175,000	175,000
	Total Avista Corp. secured long-term debt		1,814,200	1,711,700
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		1,889,200	1,786,700
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		1,904,200	1,801,700
Other Long-Term Debt Components				
	Capital lease obligations (3)		57,210	62,148
	Unamortized debt discount		(882)	(626)
	Unamortized long-term debt issuance costs		(13,654)	(10,285)
	Total		1,946,874	1,852,937
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt and capital leases		(107,645)	(277,438)
	Total long-term debt and capital leases		$ 1,755,529	$ 1,491,799

(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 May 2018, the Company issued and sold $375.0 million of 4.35 percent first mortgage bonds due in 2048 through a public offering. The total net proceeds from the sale of the bonds were used to repay maturing long-term debt of $272.5 million, repay the outstanding balance under Avista Corp.'s $400.0 million committed line of credit and for other general corporate purposes. In connection with the issuance and sale of the first mortgage bonds, the Company cash-settled fourteen interest rate swap derivatives (notional aggregate amount of $275.0 million) and paid a net amount of $26.6 million. See Note 6 for a discussion of interest rate swap derivatives.

(3) Effective January 1, 2019, due to the adoption of the new lease standard (ASU 2016-02), capital leases will now be defined as finance leases. See Note 2 for further discussion of the new lease standard.

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

	2019	2020	2021	2022	2023	Thereafter	Total
Debt maturities	$ 105,000	$ 52,000	$ —	$ 250,000	$ 13,500	$ 1,451,547	$ 1,872,047

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:

- $66^2/_3$ 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.

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, 2018, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.2 billion in aggregate principal amount of additional first mortgage bonds at Avista Utilities and $27.0 million at AEL&P.

Snettisham Capital Lease Obligation

The long-term capital lease above is a PPA 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 PPA 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):

	2018	2017
Capital lease obligation (1)	$ 57,210	$ 59,745
Capital lease asset (2)	71,007	71,007
Accumulated amortization of capital lease asset (2)	16,386	12,745

(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):

	2018	2017
Interest on capital lease obligation	$ 2,921	$ 3,042
Amortization of capital lease asset	3,641	3,641

In August 2015, AIDEA issued $65.7 million of new revenue bonds for the purpose of refunding all of the remaining outstanding revenue bonds (originally issued in 1998) for the Snettisham Hydroelectric Project. The 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 PPA. 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 PPA 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 PPA to determine if it has a variable interest which must be consolidated. Based on this evaluation, AIDEA is not 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):

	2019	2020	2021	2022	2023	Thereafter	Total
Principal	$ 2,660	$ 2,800	$ 2,935	$ 3,085	$ 3,235	$ 42,495	$ 57,210
Interest	2,795	2,662	2,522	2,375	2,221	12,079	24,654
Total	$ 5,455	$ 5,462	$ 5,457	$ 5,460	$ 5,456	$ 54,574	$ 81,864

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:

	2018	2017	2016
Low distribution rate	2.36%	1.81%	1.29%
High distribution rate	3.61%	2.36%	1.81%
Distribution rate at the end of the year	3.61%	2.36%	1.81%

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These Preferred Trust 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):

	2018		2017	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 1,053,500	$ 1,142,292	$ 951,000	$ 1,067,783
Long-term debt (Level 3)	767,000	734,742	767,000	810,598
Snettisham capital lease obligation (Level 3)	57,210	55,600	59,745	61,700
Long-term debt to affiliated trusts (Level 3)	51,547	38,145	51,547	41,882

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 74.00 to 121.49, 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, 2018.

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, 2018 and 2017 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, 2018					
Assets:					
Energy commodity derivatives	$ —	$ 36,252	$ —	$ (35,982)	$ 270
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	31	(31)	—
Interest rate swap derivatives	—	10,566	—	(440)	10,126
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities [2]	1,745	—	—	—	1,745
Equity securities [2]	6,157	—	—	—	6,157
Total	$ 7,902	$ 46,818	$ 31	$ (36,453)	$ 18,298
Liabilities:					
Energy commodity derivatives	$ —	$ 89,283	$ —	$ (87,199)	$ 2,084
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	2,805	(31)	2,774
Power exchange agreement	—	—	2,488	—	2,488
Power option agreement	—	—	1	—	1
Foreign currency exchange derivatives	—	45	—	—	45
Interest rate swap derivatives	—	7,831	—	(970)	6,861
Total	$ —	$ 97,159	$ 5,294	$ (88,200)	$ 14,253
December 31, 2017					
Assets:					
Energy commodity derivatives	$ —	$ 43,814	$ —	$ (42,550)	$ 1,264
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	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

(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 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 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 U.S. dollar and multiplies the difference between the locked-in price and the market price by the notional amount of the derivative. Forward foreign currency market curves are provided by third party brokers. The Company's credit spread is factored into the locked-in price of the foreign exchange contracts.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.5 million as of December 31, 2018 and $0.2 million as of December 31, 2017.

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. The Company 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.

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.

In addition to the above, the Company also has power option agreements which expire 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. Due to the short duration remaining for the power option agreements and their insignificant dollar value, the Company has elected to exclude these agreements from the below Level 3 disclosures.

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, 2018 (dollars in thousands):

	Fair Value (Net) at December 31, 2018	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (2,488)	Surrogate facility	O&M charges	$40.05–$52.59/MWh (1)
		pricing	Transaction volumes	173,465 MWhs
Natural gas exchange agreement	(2,774)	Internally derived	Forward purchase prices	$1.44–$1.88/mmBTU
		weighted-average	Forward sales prices	$1.47–$3.34/mmBTU
		cost of gas	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 2018 are $45.61 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	Total
Year ended December 31, 2018:			
Balance as of January 1, 2018	$ (3,164)	$ (13,245)	$ (16,409)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	326	5,027	5,353
Settlements	64	5,730	5,794
Ending balance as of December 31, 2018 (2)	$ (2,774)	$ (2,488)	$ (5,262)
Year ended December 31, 2017:			
Balance as of January 1, 2017	$ (5,885)	$ (13,449)	$ (19,334)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	3,292	(7,674)	(4,382)
Settlements	(571)	7,878	7,307
Ending balance as of December 31, 2017 (2)	$ (3,164)	$ (13,245)	$ (16,409)
Year ended December 31, 2016:			
Balance as of January 1, 2016	$ (5,039)	$ (21,961)	$ (27,000)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities (1)	259	400	659
Settlements	(1,105)	8,112	7,007
Ending balance as of December 31, 2016 (2)	$ (5,885)	$ (13,449)	$ (19,334)

(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), and
- 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.

As of December 31, 2018, the acquisition of the Company by Hydro One had not yet been terminated. As such, the Merger Agreement was still in effect at that time. Under the Merger Agreement, the annual dividends were not to increase by more than $0.06 per year over the 2017 dividend rate, thus limiting annual dividends to $1.49 per share.

Now that the Merger Agreement has been terminated, the requirements of the OPUC approval of the AERC acquisition are the most restrictive. Under the OPUC restriction, the amount available for dividends at December 31, 2018 was limited to $231.1 million.

See the Consolidated Statements of Equity for dividends declared in the years 2018 through 2016.

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2018 and 2017.

Equity Issuances

The Company has entered into four separate sales agency agreements under which the sales agents may offer and sell new shares of the Company's common stock from time to time. No shares were issued under these agreements during 2018. These agreements provide for the offering of a maximum of 3.8 million shares, of which approximately 1.1 million remain unissued as of December 31, 2018. Subject to the satisfaction of customary conditions (including any required regulatory approvals), the Company has the right to increase the maximum number of shares that may be offered under these agreements.

Note 18. Accumulated Other Comprehensive Loss

Accumulated Other Comprehensive Loss

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

	2018	2017
Unfunded benefit obligation for pensions and other postretirement benefit plans—net of taxes of $2,091 and $4,356, respectively [a]	$ 7,866	$ 8,090

(a) Effective January 1, 2018, the Company adopted ASU No. 2018-02. As a result of the adoption of this new standard, $1.7 million in excess tax benefits was reclassified from accumulated other comprehensive loss to retained earnings. See Note 2 for additional discussion of the adoption of this standard.

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

	Amounts Reclassified from Accumulated Other Comprehensive Loss			
Details about Accumulated Other Comprehensive Loss Components	**2018**	**2017**	**2016**	**Affected Line Item in Statement of Income**
Amortization of defined benefit pension items				
Amortization of net prior service cost	$ (904)	$ (4,381)	$ (1,171)	[a]
Amortization of net loss	(15,554)	36,833	(7,602)	[a]
Adjustment due to effects of regulation [b]	18,947	(33,255)	7,360	[a]
	2,489	(803)	(1,413)	Total before tax
	(523)	281	495	Tax benefit (expense)
	$ 1,966	$ (522)	$ (918)	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.

Note 19. Earnings Per Common Share Attributable to Avista Corporation Shareholders

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corp. shareholders for the years ended December 31 (in thousands, except per share amounts):

	2018	2017	2016
Numerator:			
Net income attributable to Avista Corp. shareholders	$ 136,429	$ 115,916	$ 137,228
Denominator:			
Weighted-average number of common shares outstanding—basic	65,673	64,496	63,508
Effect of dilutive securities:			
Performance and restricted stock awards	273	310	412
Weighted-average number of common shares outstanding—diluted	65,946	64,806	63,920
Earnings per common share attributable to Avista Corp. shareholders:			
Basic	$ 2.08	$ 1.80	$ 2.16
Diluted	$ 2.07	$ 1.79	$ 2.15

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

Note 20. Commitments and Contingencies

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

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, Southern California Edison, San Diego Gas & Electric, the California Attorney General, the California Department of Water Resources, and the California Public Utilities Commission (together, the "California Parties"). The penalty was the result of the FERC's finding that APX committed violations in the California market in the summer of 2000. APX made 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 identified Avista Energy's share of APX's exposure to be as much as $16.0 million even though no wrongdoing allegations were specifically attributable to Avista Energy. Avista Energy asserted its settlement with the California Parties in 2014 insulated it from any such liability and that as a dismissed party it would not be drawn back into the litigation. On May 3, 2018, the FERC issued an order, Order on Compliance Filings, resolving in the Company's favor the last indirect exposure the Company had related to the California Refund Proceedings. That order, which fully absolved the Company of any further exposure, was not challenged and is now final and not subject to appeal.

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 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.

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. The Company is currently negotiating a new agreement with the IBEW.

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 Proposed Acquisition by Hydro One

See Note 24 for information regarding the termination of the proposed acquisition of the Company by Hydro One.

In connection with the now terminated acquisition, three lawsuits were filed in the United States District Court for the Eastern District of Washington and were subsequently voluntarily dismissed by the plaintiffs.

One lawsuit was 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. While Avista Corp. is not a named defendant in this lawsuit, the Company has the obligation to indemnify members of its Board of Directors.

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 complaint seeks various remedies, including monetary damages, attorneys' fees and expenses. The complaint was stayed by the court until the closing of the transaction at which time the plaintiff would have the option to file an amended complaint within 30 days of such closing. If the amended complaint was not filed within the 30 days the suit would be dismissed. Since the transaction will not close, the status of this lawsuit is unknown.

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.

2015 Washington General Rate Cases

In January 2016, the Company received an order (Order 05) that concluded its 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.

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

In January 2016, the Industrial Customers of Northwest Utilities, the Public Counsel Unit of the Washington State Office of the Attorney General (PC) and the WUTC Staff, which is a separate party in the general rate case proceedings from the WUTC Advisory Staff, filed Motions for Clarification requesting the WUTC to clarify their attrition adjustment and the end result electric revenue amounts. The Motions for Clarification suggested that the electric revenue decrease should have been significantly larger than what was included in Order 05.

In February 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

In March 2016, PC filed in Thurston County Superior Court a Petition for Judicial Review of the WUTC's Order 05 and Order 06 described above. In April 2016, this matter was certified for review directly by the Court of Appeals, an intermediate appellate court in the State of Washington.

On August 7, 2018, the Court of Appeals issued a "Published Opinion" (Opinion) which concluded that the WUTC's use of an attrition allowance to calculate Avista Corp.'s rate base violated Washington law. In the Opinion, the Court stated that because the projected additions to rate base in the future were not "used and useful" for service at the time the request for the rate increase was made, they may not lawfully be included in the Company's rate base to justify a rate increase. Accordingly, the Court concluded that the WUTC erred in including an attrition allowance in the calculation of Avista Corp.'s electric and natural gas rate base. The Court noted, however, that the law does not prohibit an attrition allowance in the calculation, for ratemaking purposes, of recoverable operating and maintenance expense. Since the WUTC order provided one lump sum attrition allowance without distinguishing what portion was for rate base and which was for operating and maintenance expenses or other considerations, the Court struck all portions of the attrition allowance attributable to Avista Corp.'s rate base and reversed and remanded the case for the WUTC to recalculate Avista Corp.'s rates without including an attrition allowance in the calculation of rate base. On October 1, 2018, the Court of Appeals terminated its review of this case, remanding it back to the Thurston County Superior Court.

The total attrition allowance approved by the WUTC in Order 05 and reaffirmed in Order 06 was $35.2 million, with $28.3 million related to electric and $6.9 million related to natural gas. The Company believes the potential amount to return to customers is limited to the 2015 general rate cases because in subsequent Washington general rate cases (specifically those approved in April 2018), the WUTC did not include any attrition allowance on rate base. Even though the Company believes the issue only relates to the 2015 general rate cases, the Company cannot predict the outcome of this matter at this time and cannot estimate how much, if any, of the attrition allowance may be removed from the general rate cases or if other amounts from subsequent general rate cases will be included. The Company will participate in any regulatory process that is yet to be established by the WUTC.

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 21. Regulatory Matters

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities as of December 31, 2018 (dollars in thousands):

		Receiving Regulatory Treatment			2018		2017	
	Remaining Amortization Period	Earning a Return[1]	Not Earning a Return	Expected Recovery or Refund[2]	Current	Non-current	Current	Non-current
Regulatory Assets:								
Deferred income tax	(3)	$ 91,188	$ —	$ —	$ —	$ 91,188	$ —	$ 90,315
Pensions and other postretirement benefit plans	(4)	—	228,062	—	—	228,062	—	209,115
Energy commodity derivatives	(5)	—	58,294	—	41,428	16,866	24,991	18,967
Unamortized debt repurchase costs	(6)	10,255	—	—	—	10,255	—	—
Settlement with Coeur d'Alene Tribe	2059	42,643	—	—	—	42,643	—	43,954
Demand side management programs	(3)	—	19,674	—	—	19,674	—	24,620
Decoupling surcharge	2020	20,909	—	—	3,408	17,501	19,759	2,600
Utility plant to be abandoned	(7)	24,334	—	—	—	24,334	—	24,330
Interest rate swaps	(8)	94,289	—	39,565	—	133,854	—	169,704
Other regulatory assets	(3)	14,555	6,658	12,480	3,716	29,977	—	35,794
Total regulatory assets		$ 298,173	$ 312,688	$ 52,045	$ 48,552	$ 614,354	$ 44,750	$ 619,399
Regulatory Liabilities:								
Deferred natural gas costs	(3)	$ 40,713	$ —	$ —	$ 40,713	$ —	$ 37,474	$ —
Deferred power costs	(3)	42,005	—	—	25,072	16,933	5,816	24,057
Utility plant retirement costs	(9)	297,379	—	—	—	297,379	—	285,786
Income tax related liabilities	(3) (10)	436,404	16,900	306	27,997	425,613	—	460,542
Interest rate swaps	(8)	12,359	—	15,719	—	28,078	—	18,638
Decoupling rebate	2020	6,986	—	—	6,782	204	—	5,816
Other regulatory liabilities	(3)	17,280	3,704	4,155	12,645	12,494	4,974	5,250
Total regulatory liabilities		$ 853,126	$ 20,604	$ 20,180	$ 113,209	$ 780,701	$ 48,264	$ 800,089

See footnotes on the following page.

(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 PGAs, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases. The resulting regulatory assets associated with energy commodity derivative instruments 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 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. In September 2017, the WUTC also approved the Company's request to defer the undepreciated net book value of existing natural gas ERTs (consistent with the accounting treatment for the electric meters) that will be retired as part of the AMI project. Replacement of the meters and natural gas ERTs began in the second half of 2018.

(8) 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. 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.

(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 TCJA, which changed the federal income tax rate from 35 percent to 21 percent. The Company revalued all deferred income taxes as of December 31, 2017. The Company expects the amounts for utility plant items for Avista Utilities to be returned to customers over a period of approximately 36 years. The Company expects the AEL&P amounts to be returned to customers over a period of approximately 40 years. The regulatory liability attributable to non-plant excess deferred taxes is approximately $18.5 million (among all jurisdictions) as of December 31, 2018. The return of this amount to customers will be determined by final orders from the WUTC, IPUC and OPUC during 2019. 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 2018, the Company recognized a pre-tax benefit of $6.1 million under the ERM in Washington compared to a benefit of $4.6 million for 2017. Total net deferred power costs under the ERM were a liability of $34.4 million as of December 31, 2018 and a liability of $23.7 million as of December 31, 2017. These deferred power cost balances represent amounts due to customers. These deferred power cost balances represent amounts due to customers. Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million in the rebate or surcharge direction, the Company must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from customers. 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. The filing in 2019 will also contain a proposed rate adjustment or refund, effective July 1, 2019, due to the rebate balance exceeding $30 million.

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. 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

$7.6 million as of December 31, 2018 and a liability of $6.1 million as of December 31, 2017. 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 $40.7 million as of December 31, 2018 and a liability of $37.5 million as of December 31, 2017. 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. In February 2019, the WUTC approved an all-party agreement that extends the life of the mechanisms through the end of the Company's next general rate case, or April 1, 2020, whichever comes first. In that general rate case the Company will seek to either make permanent or extend the mechanisms for an additional multi-year term. 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. During the first quarter of 2018, the FCA in Idaho was extended for a one-year term through December 31, 2019. The Company expects to seek an extension of the FCAs in its next general rate case, expected in the second quarter of 2019.

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, 2018 and December 31, 2017, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2018	December 31, 2017
Washington		
Decoupling surcharge	$ 12,671	$ 14,240
Provision for earnings sharing rebate	(693)	(3,420)
Idaho		
Decoupling surcharge	$ 2,150	$ 3,471
Provision for earnings sharing rebate	(774)	(2,350)
Oregon		
Decoupling rebate	$ (898)	$ (1,168)
Provision for earnings sharing rebate	—	—

Note 22. 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, 2018:						
Operating revenues	$ 1,325,966	$ 43,599	$ 1,369,565	$ 27,328	$ —	$ 1,396,893
Resource costs	485,231	9,505	494,736	—	—	494,736
Other operating expenses [2]	309,501	12,491	321,992	28,081	—	350,073
Depreciation and amortization	177,006	5,871	182,877	799	—	183,676
Income (loss) from operations	248,000	14,665	262,665	(1,552)	—	261,113
Interest expense [3]	96,738	3,584	100,322	1,694	(1,080)	100,936
Income taxes	25,259	3,094	28,353	(2,293)	—	26,060
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	134,874	8,292	143,166	(6,737)	—	136,429
Capital expenditures [4]	418,741	5,609	424,350	891	—	425,241
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] [5]	312,229	12,532	324,761	25,650	—	350,411
Depreciation and amortization	165,478	5,803	171,281	740	—	172,021
Income (loss) from operations [5]	278,079	17,947	296,026	(3,847)	—	292,179
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 [5]	294,586	11,151	305,737	25,501	—	331,238
Depreciation and amortization	155,162	5,352	160,514	769	—	161,283
Income (loss) from operations [5]	287,128	15,434	302,562	(2,701)	—	299,861
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
Total Assets:						
As of December 31, 2018	$ 5,458,104	$ 272,950	$ 5,731,054	$ 87,050	$ (35,528)	$ 5,782,576
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

See footnotes on the following page.

(1) *Intersegment eliminations reported as interest expense represent intercompany interest. Intersegment eliminations reported as assets represent intersegment accounts receivable.*

(2) *Other operating expenses for Avista Utilities for 2018 and 2017 includes acquisition costs of $3.7 million and $14.6 million, respectively, 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.*

(5) *Effective January 1, 2018, the Company adopted ASU No. 2017-07, which resulted in a $7.7 million and $10.1 million reclassification of the non-service cost component of pension and other postretirement benefit costs for 2017 and 2016, respectively. The costs were reclassified from utility other operating expenses to other expense (income)—net on the Consolidated Statements of Income.*

Note 23. 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 2018 and 2017 follows:

	Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
2018				
Operating revenues	$ 409,361	$ 319,298	$ 296,013	$ 372,221
Operating expenses	315,155	266,019	259,569	295,037
Income from operations	$ 94,206	$ 53,279	$ 36,444	$ 77,184
Net income	54,956	25,644	10,129	45,869
Net income attributable to noncontrolling interests	(66)	(67)	(10)	(26)
Net income attributable to Avista Corporation shareholders	$ 54,890	$ 25,577	$ 10,119	$ 45,843
Outstanding common stock:				
weighted-average—basic	65,639	65,677	65,688	65,688
weighted-average—diluted	65,931	65,983	66,026	65,846
Earnings per common share attributable to Avista Corp. shareholders—diluted	$ 0.83	$ 0.39	$ 0.15	$ 0.70
2017				
Operating revenues	$ 436,470	$ 314,501	$ 297,096	$ 397,862
Operating expenses (1)	319,043	256,555	264,197	313,955
Income from operations (1)	$ 117,427	$ 57,946	$ 32,899	$ 83,907
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

(1) *Effective January 1, 2018, the Company adopted ASU No. 2017-07, which resulted in the reclassification of the non-service cost component of pension and other postretirement benefit costs from utility other operating expenses to other expense (income)—net on the Consolidated Statements of Income. There was no impact on net income. The Company reclassified $2.0 million, $1.8 million, $1.9 million and $2.0 million for the first through fourth quarters of 2017, respectively. See Note 2 for further discussion of the adoption of ASU No. 2017-07.*

Note 24. Termination of Proposed Acquisition by Hydro One

On July 19, 2017, Avista Corp. entered into a Merger Agreement that provided 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. 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 and its affiliates, were to be converted automatically into the right to receive an amount in cash equal to $53, without interest.

Denial by Regulatory Commissions

The closing of the acquisition was subject to various conditions, including, among others, receipt of regulatory approval from the WUTC, IPUC, MPSC, OPUC, and the RCA.

Washington—On March 27, 2018, Avista Corp. and Hydro One filed an all-parties (including the WUTC Staff), all-issues settlement agreement with the WUTC recommending approval of the acquisition of the Company by Hydro One. The settlement agreement was subject to WUTC approval.

On December 5, 2018, the Company and Hydro One received a decision from the WUTC, denying the proposed acquisition. On December 17, 2018, the Company and Hydro One filed a petition requesting that the WUTC reconsider its December 5, 2018 order denying approval of the acquisition, together with a petition requesting that the WUTC rehear the matter to accept new evidence. Under Washington State law, the WUTC had 20 days to act on the petition for reconsideration.

On January 8, 2019, the WUTC provided notice of its deemed denial by operation of law of the filed petition to reconsider the denial of approval for the acquisition. The WUTC did not take action on the petition within the required 20 days of its filing so the petition was automatically denied under the state's Administrative Procedure Act. In the same notice, the WUTC also denied the petition for a rehearing on the basis that it does not apply.

Idaho—On April 13, 2018, Avista Corp. and Hydro One filed an all-issues settlement agreement (to which the IPUC Staff was a party) with the IPUC recommending approval of the acquisition of the Company by Hydro One. The settlement agreement was subject to IPUC approval.

On January 3, 2019, the Company and Hydro One received a decision from the IPUC, finding that the proposed acquisition was not permitted by Idaho law. Avista Corp. and Hydro One had until January 24, 2019 to file a petition for reconsideration with the IPUC, which they did not file.

Oregon—On May 25, 2018, Avista Corp. and Hydro One filed an all-parties (including the OPUC Staff), all-issues settlement agreement with the OPUC related to the Oregon merger proceeding. The settlement agreement was subject to review and approval by the OPUC.

On January 15, 2019, due to the denial of the acquisition by the WUTC and IPUC, the OPUC issued an order suspending indefinitely the procedural schedule in its merger docket until Hydro One and Avista Corp. informed the OPUC that they had sought a reversal of the denial decisions through appeal or other means that would provide a justiciable issue for the OPUC to address.

Termination of the Merger Agreement

On January 23, 2019, Avista Corp., Hydro One and certain subsidiaries thereof, entered into a Termination Agreement indicating their mutual agreement to terminate the Merger Agreement, effective immediately. Pursuant to the terms of the Termination Agreement, Hydro One paid Avista Corp. a $103 million termination fee on January 24, 2019. The termination fee will be used for reimbursing the Company's transaction costs incurred from 2017 to 2019. The balance of the termination fee remaining after payment of 2019 transaction costs and applicable income taxes will be used for general corporate purposes and reduces the Company's need for external financing.

Other Information Related to the Terminated Acquisition

Due to the termination of the acquisition, all the financial commitments that were included in the various settlement agreements with the commissions for the proposed acquisition will not occur.

The Company incurred significant acquisition costs associated with the acquisition consisting primarily of consulting, banking fees, legal fees and employee time, and these costs are not being passed through to customers. When the Company was assuming the transaction was going to be completed, a significant portion of these costs were not deductible for income tax purposes. Now that the transaction has been terminated, the Company expects more of the previously incurred transaction costs to be deductible so it expects additional tax benefits from these costs in 2019.

See Note 20 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.

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, 2018.

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, 2018 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, 2018.

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, 2018, 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, 2018, 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, 2018], of the Company and our report dated February 19, 2019, 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 19, 2019

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item (other than the information regarding executive officers and the Company's Code of Business Conduct and Ethics set forth below) is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 9, 2019, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 29, 2018, relating to its Annual Meeting of Shareholders held on May 10, 2018.

Executive Officers of the Registrant

Name	Age	Business Experience
Scott L. Morris	61	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	55	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	65	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 Air Lines, Inc. from 1995–August 2005, most recently served as Vice President Deputy General Counsel and Assistant Secretary.
Karen S. Feltes	63	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	57	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	48	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	49	Vice President, Controller and Principal Accounting Officer since October 2015; various other management and staff positions with the Company since 2001.
Kevin J. Christie	51	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	60	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	65	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	41	Vice President of Energy Delivery since December 2015; various other management and staff positions with the Company since 1996.
Edward D. Schlect Jr.	58	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	49	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 2018. 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 9, 2019, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 29, 2018, relating to its Annual Meeting of Shareholders held on May 10, 2018.

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 9, 2019, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 29, 2018, relating to its Annual Meeting of Shareholders held on May 10, 2018; 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 9, 2019, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 29, 2018, relating to its Annual Meeting of Shareholders held on May 10, 2018.

(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)]	—	$ —	1,320,909

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long-Term Incentive Plan. At December 31, 2018, 91,998 Restricted Share awards were outstanding. Performance and market-based share awards may be paid out at zero shares at a minimum achievement level; 280,751 shares at target level; or 561,502 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 (amended in 2016) and the Non-Employee Director Stock Plan approved by shareholders in 1996. In February 2005, the Board of Directors elected to terminate the Non-Employee Director Stock Plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 9, 2019, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 29, 2018, relating to its Annual Meeting of Shareholders held on May 10, 2018.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 9, 2019, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 29, 2018, relating to its Annual Meeting of Shareholders held on May 10, 2018.

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, 2018, 2017 and 2016

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2018, 2017 and 2016

Consolidated Balance Sheets as of December 31, 2018 and 2017

Consolidated Statements of Cash Flows for the Years Ended December 31, 2018, 2017 and 2016

Consolidated Statements of Equity for the Years Ended December 31, 2018, 2017 and 2016

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).

Exhibit	With Registration Number	Previously Filed [1] as Exhibit	
2.1	(with Form 8-K filed as of July 19, 2017)	2.1	Agreement and Plan of Merger, dated as of July 19, 2017, by and among Avista Corporation, Hydro One Limited, Olympus Holding Corp. and Olympus Corp.
2.2	(with Form 8-K filed as of January 23, 2019)	2.1	Termination Agreement, dated as of January 23, 2019, by and among Avista Corporation, Hydro One Limited, Olympus Holding Corp. and Olympus Corp.
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.

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

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

Exhibit	With Registration Number	Previously Filed [1] as Exhibit	
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.
4.62	(with Form 8-K date as of May 15, 2018)	4(a)(62)	Sixty-First Supplemental Indenture, dated as of May 1, 2018.
4.63	(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.
4.64	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.65	(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.
4.66	(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.
4.67	(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.
4.68	(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.
4.69	(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).
4.70	(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).
4.71	(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 Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.

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

Exhibit	With Registration Number	Previously Filed [1] as Exhibit	
10.14	(with 2017 Form 10-K)	10.14	Avista Corporation Executive Deferral Plan. [3][5]
10.15	(with 2017 Form 10-K)	10.15	Avista Corporation Executive Deferral Plan. [3][6]
10.16	(with 2017 Form 10-K)	10.16	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]
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	[2]		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 2016 Form 10-K)	10.24	Avista Corporation Performance Award Agreement 2016. [3]
10.24	(with 2017 Form 10-K)	10.25	Avista Corporation Performance Award Agreement 2017. [3]
10.25	[2]		Avista Corporation Performance Award Agreement 2018. [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	(with 2010 Form 10-K)	10.28	Form of Change of Control Agreement between the Company and its Executive Officers. [3][8]
10.29	(with 2010 Form 10-K)	10.29	Form of Change of Control Agreement between the Company and its Executive Officers. [3][9]
10.30	(with 2010 Form 10-K)	10.30	Form of Change of Control Agreement between the Company and its Executive Officers. [3][10]
10.31	(with 2010 Form 10-K)	10.31	Form of Change of Control Agreement between the Company and its Executive Officers. [3][11]
10.32	[2]		Avista Corporation Non-Employee Director Compensation.
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).

Exhibit	With Registration Number	Previously Filed [1] as Exhibit	
31.2	[2]		Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).
32	[4]		Certification of Corporate Officers (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).
101	[2]		The following financial information from the Annual Report on Form 10-K for the period ended December 31, 2018, 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 and Bryan A. Cox.

(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, Edward D. Schlect and Bryan A. Cox.

(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.

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 19, 2019	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 19, 2019
/s/ Mark T. Thies Mark T. Thies Senior Vice President, Chief Financial Officer, and Treasurer	Principal Financial Officer	February 19, 2019
/s/ Ryan L. Krasselt Ryan L. Krasselt Vice President, Controller and Principal Accounting Officer	Principal Accounting Officer	February 19, 2019
/s/ Dennis P. Vermillion Dennis P. Vermillion President	Director	February 19, 2019
/s/ Erik J. Anderson Erik J. Anderson	Director	February 19, 2019
/s/ Kristianne Blake Kristianne Blake	Director	February 19, 2019
/s/ Donald C. Burke Donald C. Burke	Director	February 19, 2019
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 19, 2019
/s/ Scott H. Maw Scott H. Maw	Director	February 19, 2019
/s/ Marc F. Racicot Marc F. Racicot	Director	February 19, 2019
/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 19, 2019
/s/ R. John Taylor R. John Taylor	Director	February 19, 2019
/s/ Janet D. Widmann Janet D. Widmann	Director	February 19, 2019

Avista Corporation

SUBSIDIARIES OF REGISTRANT

Subsidiary	State or County 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 S-8 and in Registration Statement No.333-209714 on Form S-3 of our reports dated February 19, 2019, relating to the 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, 2018.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 19, 2019

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 19, 2019

/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 19, 2019

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

Certification of Corporate Officers

(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

Each of the undersigned, Scott L. Morris, Chairman of the Board, President and Chief Executive Officer of Avista Corporation (the "Company"), and Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Annual Report on Form 10-K for the year ended December 31, 2018 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 19, 2019

/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

	2018	2017	2016	2015	2014	2008
FINANCIAL RESULTS						
Operating revenues	$ 1,396,893	$ 1,445,929	$ 1,442,483	$ 1,484,776	$ 1,472,562	$ 1,617,678
Operating expenses [1]	1,135,780	1,153,750	1,142,622	1,223,204	1,216,415	1,446,039
Income from continuing operations [1]	261,113	292,179	299,861	261,572	256,147	171,639
Interest expense	100,936	96,192	87,130	80,441	75,752	79,477
Income taxes	26,060	82,758	78,086	67,449	72,240	41,558
Net income from continuing operations	136,598	115,932	137,316	118,170	119,866	68,667
Net income (loss) from discontinued operations	—	—	—	5,147	72,411	6,090
Net income	136,598	115,932	137,316	123,317	192,277	74,757
Net income attributable to noncontrolling interests	(169)	(16)	(88)	(90)	(236)	(1,137)
Net income attributable to Avista Corp. shareholders:						
Net income from continuing operations attributable to Avista Corp. shareholders	$ 136,429	$ 115,916	$ 137,228	$ 118,080	$ 119,817	$ 67,530
Net income from discontinued operations attributable to Avista Corp. shareholders	—	—	—	5,147	72,224	6,090
Net income attributable to Avista Corp. shareholders	$ 136,429	$ 115,916	$ 137,228	$ 123,227	$ 192,041	$ 73,620
Earnings per common share attributable to Avista Corp. shareholders—diluted:						
Earnings from continuing operations	$ 2.07	$ 1.79	$ 2.15	$ 1.89	$ 1.93	$ 1.25
Earnings from discontinued operations	—	—	—	0.08	1.17	0.11
Total	$ 2.07	$ 1.79	$ 2.15	$ 1.97	$ 3.10	$ 1.36
Earnings per common share attributable to Avista Corp. shareholders—basic:	$ 2.08	$ 1.80	$ 2.16	$ 1.98	$ 3.12	$ 1.37
COMMON STOCK STATISTICS						
Dividends paid per common share	$ 1.49	$ 1.43	$ 1.37	$ 1.32	$ 1.27	$ 0.690
Book value per common share	$ 26.99	$ 26.41	$ 25.69	$ 24.53	$ 23.84	$ 18.30
Shares of common stock:						
Outstanding at year-end	65,688	65,494	64,188	62,313	62,243	54,488
Average—basic	65,673	64,496	63,508	62,301	61,632	53,637
Average—diluted	65,946	64,806	63,920	62,708	61,887	54,028
Return on average Avista Corp. stockholders' equity:						
Total company	7.8 %	6.9 %	8.6 %	8.2 %	13.7 %	7.7 %
Utility only	8.5 %	7.5 %	9.2 %	8.4 %	9.0 %	8.0 %
Non-utility only	1.0 %	0.7 %	3.0 %	6.5 %	54.4 %	4.9 %
Common stock price:						
High	$ 52.91	$ 52.74	$ 44.97	$ 38.30	$ 37.37	$ 23.30
Low	$ 42.48	$ 37.94	$ 34.67	$ 29.93	$ 27.71	$ 16.58
Year-end close	$ 42.48	$ 51.49	$ 39.99	$ 35.37	$ 35.35	$ 19.38
DEBT AND PREFERRED STOCK STATISTICS						
Pretax interest coverage:						
Including AFUDC/AFUCE	2.67(x)	3.11(x)	3.54(x)	3.46(x)	4.52(x)	2.45(x)
Excluding AFUDC/AFUCE	2.57(x)	3.00(x)	3.43(x)	3.31(x)	4.35(x)	2.32(x)
Embedded cost of long-term debt	5.33%	5.58 %	5.55 %	5.31 %	5.37 %	6.69 %

(1) Operating expenses and income from continuing operations for the periods 2017 through 2014 and 2008 were adjusted in accordance with a change in accounting standards.

Avista Corporation

As of and for the years ended December 31,

Dollars in thousands, except per share data and ratios

	2018	2017	2016	2015	2014	2008
FINANCIAL CONDITION						
Total assets [2] [3]	$ 5,782,576	$ 5,514,732	$ 5,309,755	$ 4,906,649	$ 4,700,971	$ 3,491,352
Total net Avista Utilities property	4,450,078	4,196,691	3,943,087	3,702,691	3,427,641	2,492,191
Avista Utilities property capital expenditures (excluding equity-related AFUDC)	418,741	405,938	390,690	381,174	323,931	219,239
Long-term debt (including current portion) [3]	1,863,174	1,769,237	1,682,004	1,573,278	1,487,126	812,981
Nonrecourse long-term debt of Spokane Energy (including current portion)	—	—	—	—	1,431	—
Long-term debt to affiliated trusts	51,547	51,547	51,547	51,547	51,547	113,403
Avista Corporation stockholders' equity	$ 1,773,220	$ 1,729,828	$ 1,648,727	$ 1,528,626	$ 1,483,671	$ 996,883
AVISTA UTILITIES						
Electric Operations						
Electric operating revenues (millions of dollars):						
Residential	$ 368.8	$ 381.7	$ 339.2	$ 335.5	$ 338.7	$ 279.6
Commercial	314.5	311.6	305.6	308.2	300.1	247.7
Industrial	109.8	111.0	107.3	111.8	110.8	101.8
Public street and highway lighting	7.5	7.5	7.7	7.3	7.5	6.0
Total retail	800.6	811.8	759.8	762.8	757.1	635.1
Wholesale	85.0	81.5	112.1	127.3	138.2	141.8
Sales of fuel	62.2	64.9	78.3	82.9	83.7	44.7
Other	29.3	31.6	28.5	25.8	27.5	16.9
Decoupling	4.9	(8.2)	17.4	4.7	—	—
Provision for earning sharing	(11.5)	(1.2)	0.9	(5.6)	(7.5)	—
Total electric operating revenues	$ 970.5	$ 980.4	$ 997.0	$ 997.9	$ 999.0	$ 838.5
Electric energy sales (millions of kWhs):						
Residential	3,627	3,840	3,528	3,571	3,694	3,744
Commercial	3,156	3,222	3,183	3,197	3,189	3,188
Industrial	1,772	1,815	1,763	1,812	1,868	2,059
Public street and highway lighting	18	20	23	23	25	26
Total retail	8,573	8,897	8,497	8,603	8,776	9,017
Wholesale	3,632	2,881	2,998	3,145	3,686	1,964
Total electric energy sales	12,205	11,778	11,495	11,748	12,462	10,981
Retail electric customers (average per year):						
Residential	340,308	334,848	330,699	327,057	324,188	311,381
Commercial	42,618	42,154	41,785	41,296	40,988	39,075
Industrial	1,318	1,328	1,342	1,353	1,385	1,388
Public street and highway lighting	594	569	558	529	531	434
Total retail electric customers	384,838	378,899	374,384	370,235	367,092	352,278

(2) The total assets at year-end for 2008 exclude the total assets associated with Ecova of $125.9 million.

(3) The total assets and total long-term debt and capital leases for 2014 and 2008 were adjusted in accordance with a change in accounting standards.

Avista Corporation

As of and for the years ended December 31,

	2018	2017	2016	2015	2014	2008
Electric Operations (continued)						
Retail electric customers (at year-end):						
Residential	342,996	337,936	333,346	330,749	326,917	313,660
Commercial	42,621	42,280	41,921	42,182	41,264	39,173
Industrial	1,297	1,320	1,328	1,362	1,378	1,384
Public street and highway lighting	604	595	564	555	527	440
Total retail electric customers	387,518	382,131	377,159	374,848	370,086	354,657
Revenue per residential kWh (cents)	10.17	9.94	9.62	9.40	9.17	7.47
Use per residential customer (kWh)	10,658	11,469	10,667	10,827	11,394	12,023
Revenue per commercial kWh (cents)	9.97	9.67	9.60	9.64	9.41	7.77
Use per commercial customer (kWh)	74,059	76,444	76,166	76,638	77,814	81,583
Electric energy resources (millions of kWhs):						
Hydro generation (from Company facilities)	4,029	3,978	3,836	3,434	4,143	3,851
Thermal generation (from Company facilities)	3,424	3,476	3,626	3,983	3,252	3,693
Purchased power	5,349	4,809	4,597	4,899	5,615	4,086
Power exchanges	(109)	(6)	(6)	(2)	(25)	(17)
Total power resources	12,693	12,257	12,053	12,314	12,985	11,613
Energy losses and company use	(488)	(479)	(558)	(566)	(523)	(632)
Total electric energy resources	12,205	11,778	11,495	11,748	12,462	10,981
Retail Native Load at time of system peak						
Winter	1,555	1,681	1,655	1,529	1,715	1,821
Summer	1,716	1,596	1,587	1,638	1,606	1,602
Natural Gas Operations						
Natural gas operating revenues (millions of dollars):						
Residential	$ 194.3	$ 220.2	$ 195.3	$ 193.8	$ 203.4	$ 276.4
Commercial	89.4	104.2	93.0	96.8	103.2	152.1
Industrial and interruptible	4.8	5.7	5.5	6.5	6.9	12.2
Total retail	288.5	330.1	293.8	297.1	313.5	440.7
Wholesale	137.1	142.7	153.5	204.3	228.2	281.7
Transportation	9.1	9.2	8.3	8.0	7.7	6.3
Other	6.8	6.4	5.8	5.6	7.5	5.5
Decoupling	(4.0)	(11.4)	12.3	6.0	—	—
Provision for earning sharing	(6.8)	(2.4)	(2.8)	—	(0.2)	—
Total natural gas operating revenues	$ 430.7	$ 474.6	$ 470.9	$ 521.0	$ 556.7	$ 734.2
Natural gas therms delivered (millions of therms):						
Residential	208.3	222.0	186.6	176.6	190.2	210.1
Commercial	124.7	133.3	112.7	107.9	116.7	128.2
Industrial and interruptible	11.6	11.8	10.9	9.8	10.7	12.2
Total retail	344.6	367.1	310.2	294.3	317.6	350.5
Wholesale	503.9	545.3	684.3	809.1	545.6	345.9
Transportation and other	176.8	186.7	178.8	165.0	162.7	149.3
Total natural gas therms delivered	1,025.3	1,099.1	1,173.3	1,268.4	1,025.9	845.7

Avista Corporation

As of and for the years ended December 31,

	2018	2017	2016	2015	2014	2008
Natural Gas Operations (continued)						
Retail natural gas customers (average per year):						
Residential	314,800	307,375	300,883	296,005	291,928	277,892
Commercial	35,488	35,192	34,868	34,229	34,047	32,901
Industrial and interruptible	285	288	292	296	301	297
Total retail natural gas customers	350,573	342,855	336,043	330,530	326,276	311,090
Retail natural gas customers (at year-end):						
Residential	318,847	311,518	304,814	299,509	294,993	280,687
Commercial	35,668	35,353	35,032	34,775	34,267	33,123
Industrial and interruptible	284	289	285	289	304	292
Total retail natural gas customers	354,799	347,160	340,131	334,573	329,564	314,102
Revenue per residential therm (in dollars)	0.93	0.99	1.05	1.10	1.07	1.32
Use per residential customer (therms)	662	722	620	593	651	756
Revenue per commercial therm (in dollars)	0.72	0.78	0.83	0.90	0.88	1.19
Use per commercial customer (therms)	3,513	3,789	3,232	3,128	3,429	3,897
Heating degree days (at Spokane, Washington):						
Actual	6,159	6,783	5,790	5,614	6,215	7,052
30 year average	6,593	6,578	6,680	6,726	6,748	6,820
Actual as a percent of average	93 %	103 %	87 %	83 %	92 %	103 %
ALASKA ELECTRIC LIGHT AND POWER COMPANY						
Revenues (millions of dollars)	43.6	53.0	46.3	44.8	21.6	—
Total assets (millions of dollars)	273.0	278.7	273.8	265.7	263.1	—
ECOVA						
Revenues (millions of dollars)	$ —	$ —	$ —	$ —	$ 87.5	$ 59.1
Total assets (millions of dollars)	$ —	$ —	$ —	$ —	$ —	$ 125.9
OTHER						
Revenues (millions of dollars)	$ 27.3	$ 22.5	$ 23.6	$ 28.7	$ 39.2	$ 45.0
Total assets (millions of dollars)	$ 87.1	$ 73.2	$ 60.4	$ 39.2	$ 80.1	$ 70.0

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 investor.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 9, 2019, at Avista Corp. headquarters, 1411 East Mission Avenue, Spokane, Washington.

The annual meeting will be webcast. Please go to investor.avistacorp.com to preregister for the webcast and to listen to the live webcast. The webcast will be archived at investor.avistacorp.com for one year to allow shareholders to listen at their convenience.

EXCHANGE LISTING

Ticker Symbol: AVA
New York Stock Exchange

CERTIFICATIONS

On June 1, 2018, 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 2018, 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 2018. Our 2018 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 2018 annual report is produced through a partnership of Avista employees and companies within Avista's service area. Design and Production: Klündt | Hosmer; Photography: Dean Davis Photography; 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:
INVESTOR.AVISTACORP.COM

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