AVISTA CORP
Form 10-K
February 20, 2019
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K
(Mark One)
x 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
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO
Commission file number 1-3701

AVISTA CORPORATION
(Exact name of Registrant as specified in its charter)

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

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

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

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

Securities registered pursuant to Section 12(g) of the Act:
Title of Class
Preferred Stock, Cumulative, Without Par Value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes o No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days: Yes x No o
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 x No o
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. x

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,” “smaller reporting company,” and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	x	Accelerated filer	o
Non-accelerated filer	o	Smaller reporting company	o
Emerging growth company	o		

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. o

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

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 on 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

Table of Contents

AVISTA CORPORATION

INDEX

Table of Contents

AVISTA CORPORATION

Table of Contents

AVISTA CORPORATION

* = not an applicable item in the 2018 calendar year for Avista Corp.

Table of Contents

AVISTA CORPORATION

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
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

Table of Contents

AVISTA CORPORATION

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
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

Table of Contents

AVISTA CORPORATION

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," "pr 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;

1

Table of Contents

AVISTA CORPORATION

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;

2

Table of Contents

AVISTA CORPORATION

- 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

3

Table of Contents

AVISTA CORPORATION

- 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

Table of Contents

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:

(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.

Table of Contents

AVISTA CORPORATION

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:

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

Table of Contents

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.

Table of Contents

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

(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 forecast assumes near normal hydroelectric generation.
(3) Includes the Lancaster Plant PPA. Excludes Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT, as these are considered peaking facilities and are generally not used to meet our base load requirements.
(4) Other contracts for power purchases includes power purchase agreements for solar and wind energy.
(5) The combined maximum capacity of Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT is 278 MW, with estimated available energy production as indicated for each year.

In August 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

Table of Contents

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

Table of Contents

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.

Table of Contents

AVISTA CORPORATION

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

Table of Contents

AVISTA CORPORATION

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

	Years Ended December 31,		
	2018	2017	2016
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).

Table of Contents

AVISTA CORPORATION

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).

Table of Contents

AVISTA CORPORATION

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:

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.

Table of Contents

AVISTA CORPORATION

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).

19

Table of Contents

AVISTA CORPORATION

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.

20

Table of Contents

AVISTA CORPORATION

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

Table of Contents

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.

Table of Contents

AVISTA CORPORATION

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

Table of Contents

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.

26

Table of Contents

AVISTA CORPORATION

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.

Table of Contents

AVISTA CORPORATION

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.

Table of Contents

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.

Table of Contents

AVISTA CORPORATION

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.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Avista Corp. Market Information and Dividend Policy

Avista Corp.'s common stock is 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.

30

Table of Contents

AVISTA CORPORATION

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

(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

31

Table of Contents

AVISTA CORPORATION

(in thousands, except per share data and ratios)	Years Ended December 31,				
	2018	2017	2016	2015	2014
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
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

32

Table of Contents

AVISTA CORPORATION

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.

Table of Contents

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.

Table of Contents

AVISTA CORPORATION

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

Table of Contents

AVISTA CORPORATION

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

Table of Contents

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

Table of Contents

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.

Table of Contents

AVISTA CORPORATION

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):

(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.

Table of Contents

AVISTA CORPORATION

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)

Table of Contents

AVISTA CORPORATION

(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

Table of Contents

AVISTA CORPORATION

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 $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.

Table of Contents

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):

(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.

Table of Contents

AVISTA CORPORATION

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.

Table of Contents

AVISTA CORPORATION

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 it also includes revenues and rebates from decoupling.

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

51

(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

Table of Contents

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.

Table of Contents

AVISTA CORPORATION

- 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.

Table of Contents

AVISTA CORPORATION

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

Table of Contents
AVISTA CORPORATION

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.

Table of Contents

AVISTA CORPORATION

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:

- 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.

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.

Table of Contents

AVISTA CORPORATION

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:

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.

Table of Contents

AVISTA CORPORATION

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	Baa2

(1) Standard & Poor’s lowest “investment grade” credit rating is BBB-.

(2) Moody’s lowest “investment grade” credit rating is Baa3.

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

Table of Contents

AVISTA CORPORATION

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.

Table of Contents

(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,

66

- 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; and professional and business services; 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

Table of Contents

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 Supr