APPENDIX 6

AVISTA'S FINANCIAL STATEMENTS

(FORMS 10K/10Q)

AND

HYDRO ONE LIMITED'S

FINANCIAL STATEMENTS

(2016 Annual Report & 2016 Annual Information Form)

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

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE FISCAL YEAR ENDED December 31, 2016 OR

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

Commission file number 1-3701

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

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

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

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

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

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

Title of Class
Preferred Stock, Cumulative, Without Par Value

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

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

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

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

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

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

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

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

The aggregate market value of the Registrant's outstanding Common Stock, no par value (the only class of voting stock), held by non-affiliates is $2,853,952,416 based on the last reported sale price thereof on the consolidated tape on June 30, 2016.

As of January 31, 2017, 64,311,891 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 11, 2017. Prior to such filing, the Proxy Statement filed in connection with the annual meeting of shareholders held on May 12, 2016.	**Part III, Items 10, 11, 12, 13 and 14**

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* = not an applicable item in the 2016 calendar year for Avista Corp.

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

Acronym/Term		Meaning
aMW	-	Average Megawatt - a measure of the average rate at which a particular generating source produces energy over a period of time
AEL&P	-	Alaska Electric Light and Power Company, the primary operating subsidiary of AERC, which provides electric services in Juneau, Alaska
AERC	-	Alaska Energy and Resources Company, the Company's wholly-owned subsidiary based in Juneau, Alaska
AFUDC	-	Allowance for Funds Used During Construction; represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
AM&D	-	Advanced Manufacturing and Development, does business as METALfx
ASC	-	Accounting Standards Codification
ASU	-	Accounting Standards Update
Avista Capital	-	Parent company to the Company’s non-utility businesses
Avista Corp.	-	Avista Corporation, the Company
Avista Energy	-	Avista Energy, Inc., an inactive electricity and natural gas marketing, trading and resource management business, subsidiary of Avista Capital
Avista Utilities	-	Operating division of Avista Corp. (not a subsidiary) comprising the regulated utility operations in the Pacific Northwest
BPA	-	Bonneville Power Administration
Capacity	-	The rate at which a particular generating source is capable of producing energy, measured in KW or MW
Cabinet Gorge	-	The Cabinet Gorge Hydroelectric Generating Project, located on the Clark Fork River in Idaho
CIAC	-	Contribution in aid of construction
Colstrip	-	The coal-fired Colstrip Generating Plant in southeastern Montana
Coyote Springs 2	-	The natural gas-fired combined-cycle Coyote Springs 2 Generating Plant located near Boardman, Oregon
CT	-	Combustion turbine
Deadband or ERM deadband	-	The first $4.0 million in annual power supply costs above or below the amount included in base retail rates in Washington under the ERM in the state of Washington
Dekatherm	-	Unit of measurement for natural gas; a dekatherm is equal to approximately one thousand cubic feet (volume) or 1,000,000 BTUs (energy)
Ecology	-	The state of Washington’s Department of Ecology
Ecova	-	Ecova, Inc., a provider of facility information and cost management services for multi-site customers and energy efficiency program management for commercial enterprises and utilities throughout North America, subsidiary of Avista Capital. Ecova was sold on June 30, 2014.
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

IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
Jackson Prairie	-	Jackson Prairie Natural Gas Storage Project, an underground natural gas storage field located near Chehalis, Washington
Juneau	-	The City and Borough of Juneau, Alaska
kV	-	Kilovolt (1000 volts): a measure of capacity on transmission lines
KW, KWh	-	Kilowatt (1000 watts): a measure of generating output or capability. Kilowatt-hour (1000 watt hours): a measure of energy produced
Lancaster Plant	-	A natural gas-fired combined cycle combustion turbine plant located in Idaho
LNG	-	Liquefied Natural Gas
MPSC	-	Public Service Commission of the State of Montana
MW, MWh	-	Megawatt: 1000 KW. Megawatt-hour: 1000 KWh
NERC	-	North American Electricity Reliability Corporation
Noxon Rapids	-	The Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana
OPUC	-	The Public Utility Commission of Oregon
PCA	-	The Power Cost Adjustment mechanism, a procedure for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Idaho
PGA	-	Purchased Gas Adjustment
PPA	-	Power Purchase Agreement
PUD	-	Public Utility District
PURPA	-	The Public Utility Regulatory Policies Act of 1978, as amended
RCA	-	The Regulatory Commission of Alaska
REC	-	Renewable energy credit
Salix	-	Salix, Inc., a subsidiary of Avista Capital, launched in 2014 to explore markets that could be served with LNG, primarily in western North America.
Spokane Energy	-	Spokane Energy, LLC (dissolved in the third quarter of 2015), a special purpose limited liability company and all of its membership capital was owned by Avista Corp.
Therm	-	Unit of measurement for natural gas; a therm is equal to approximately one hundred cubic feet (volume) or 100,000 BTUs (energy)
UTC	-	Washington Utilities and Transportation Commission
Watt	-	Unit of measurement for electricity; a watt is equal to the rate of work represented by a current of one ampere under a pressure of one volt

Forward-Looking Statements

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

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

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

Forward-looking statements (including those made in this Annual Report on Form 10-K) are subject to a variety of risks and uncertainties and other factors. Most of these factors are beyond our control and may have a significant effect on our operations, results of operations, financial condition or cash flows, which could cause actual results to differ materially from those anticipated in our statements. Such risks, uncertainties and other factors include, among others:

Financial Risk

- weather conditions (temperatures, precipitation levels and wind patterns), including those from long-term climate change, which affect both energy demand and electric generating capability, including the effect of precipitation and temperature on hydroelectric resources, the effect of wind patterns on wind-generated power, weather-sensitive customer demand, and similar effects on supply and demand in the wholesale energy markets;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions and the global economy;
- changes in interest rates that affect borrowing costs, our ability to effectively hedge interest rates for anticipated debt issuances, variable interest rate borrowing and the extent to which we recover interest costs through retail rates collected from customers;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement benefit plans, which can affect future funding obligations, pension and other postretirement benefit expense and the related liabilities;
- deterioration in the creditworthiness of our customers;
- the outcome of legal proceedings and other contingencies;
- economic conditions in our service areas, including the economy's effects on customer demand for utility services;
- declining energy demand related to customer energy efficiency and/or conservation measures;

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, financing costs and commodity costs and regulatory discretion over authorized return on investment;
- possibility that our integrated resource plans for electric and natural gas will not be acknowledged by the state commissions;
- the effect on any or all of the foregoing, resulting from changes in general economic or political factors;

Energy Commodity Risk

- volatility and illiquidity in wholesale energy markets, including the availability of willing buyers and sellers, changes in wholesale energy prices that can affect operating income, cash requirements to purchase electricity and natural gas, value received for wholesale sales, collateral required of us by counterparties in wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;
- default or nonperformance on the part of any parties from whom we purchase and/or sell capacity or energy;
- potential environmental regulations affecting our ability to utilize or resulting in the obsolescence of our power supply resources;

Operational Risk

- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, snow and ice storms, that can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies and support services;
- explosions, fires, accidents, mechanical breakdowns or other incidents that may impair assets and may disrupt operations of any of our generation facilities, transmission, and electric and natural gas distribution systems or other operations and may require us to purchase replacement power;
- wildfires, including those caused by our transmission or electric distribution systems that may result in public injuries or property damage;
- public injuries or damage arising from or allegedly arising from our operations;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- terrorist attacks, cyber attacks or other malicious acts that may disrupt or cause damage to our utility assets or to the national or regional economy in general, including any effects of terrorism, cyber attacks or vandalism that damage or disrupt information technology systems;
- work force issues, including changes in collective bargaining unit agreements, strikes, work stoppages, the loss of key executives, availability of workers in a variety of skill areas, and our ability to recruit and retain employees;
- increasing costs of insurance, more restrictive coverage terms and our ability to obtain insurance;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- increasing health care costs and cost of health insurance provided to our employees and retirees;
- third party construction of buildings, billboard signs, towers or other structures within our rights of way, or placement of fuel receptacles within close proximity to our transformers or other equipment, including overbuild atop natural gas distribution lines;
- the loss of key suppliers for materials or services or disruptions to the supply chain;
- adverse impacts to our Alaska operations that could result from an extended outage of its hydroelectric generating resources or their inability to deliver energy, due to their lack of interconnectivity to any other electrical grids and the extensive cost of replacement power (diesel);
- changing river regulation at hydroelectric facilities not owned by us, which could impact our hydroelectric facilities downstream;

Compliance Risk

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

Technology Risk

- cyber attacks on us or our vendors or other potential lapses that result in unauthorized disclosure of private information, which could result in liabilities against us, costs to investigate, remediate and defend, and damage to our reputation;

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

Strategic Risk

- growth or decline of our customer base and the extent to which new uses for our services may materialize or existing uses may decline, including, but not limited to, the effect of the trend toward distributed generation at customer sites;
- potential difficulties in integrating acquired operations and in realizing expected opportunities, diversions of management resources, loss of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities;
- the potential effects of negative publicity regarding business practices, whether true or not, which could result in litigation or a decline in our common stock price;
- changes in our strategic business plans, which may be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses and the extent of our business development efforts where potential future business is uncertain;
- non-regulated activities may increase earnings volatility;

External Mandates Risk

- changes in environmental laws, regulations, decisions and policies, including present and potential environmental remediation costs and our compliance with these matters;
- the potential effects of legislation or administrative rulemaking at the federal, state or local levels, including possible effects on our generating resources of restrictions on greenhouse gas emissions to mitigate concerns over global climate changes;
- political pressures or regulatory practices that could constrain or place additional cost burdens on our distribution systems through accelerated adoption of distributed generation or electric-powered transportation or on our energy supply sources, such as campaigns to halt coal-fired power generation and opposition to other thermal generation, wind turbines or hydroelectric facilities;
- wholesale and retail competition including alternative energy sources, growth in customer-owned power resource technologies that displace utility-supplied energy or that may be sold back to the utility, and alternative energy suppliers and delivery arrangements;
- failure to identify changes in legislation, taxation and regulatory issues which are detrimental or beneficial to our overall business;
- policy and/or legislative changes resulting from the new presidential administration in various regulated areas, including, but not limited to, potential tax reform, environmental regulation and healthcare regulations; and
- the risk of municipalization in any of our service territories.

Our expectations, beliefs and projections are expressed in good faith. We believe they are reasonably based on, without limitation, an examination of historical operating trends, our records and other information available from third parties. However, there can be no assurance that our expectations, beliefs or projections will be achieved or accomplished. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time-to-time, and it is not possible for us to predict all such factors, nor can we assess the effect of each such factor on our business or the extent that any such factor or combination of factors may cause actual results to differ materially from those contained in any forward-looking statement.

Available Information

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

PART I

ITEM 1. BUSINESS

COMPANY OVERVIEW

Avista Corp., incorporated in the territory of Washington in 1889, is primarily an electric and natural gas utility with certain other business ventures. As of December 31, 2016, we employed 1,742 people in our Pacific Northwest utility operations (Avista Utilities) and 240 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, 2016, we have two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. (not a subsidiary) that comprises our regulated utility operations in the Pacific Northwest. Avista Utilities generates, transmits and distributes electricity and distributes natural gas, serving electric and natural gas customers in eastern Washington and northern Idaho and natural gas customers in parts of Oregon. We also supply electricity to a small number of customers in Montana, most of whom are our employees who operate our 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 our 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 acquired AERC on July 1, 2014, and as of that date, AERC became a wholly-owned subsidiary of Avista Corp. See "Note 4 of the Notes to Consolidated Financial Statements" for further discussion regarding this acquisition.

We have other businesses, including sheet metal fabrication, venture fund investments, real estate investments, a company that explores markets that could be served with LNG, 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., including AM&D, doing business as METALfx.

Total Avista Corp. shareholders' equity was $1,648.7 million as of December 31, 2016, of which $60.7 million represented our investment in Avista Capital and $101.1 million represented our investment in AERC.

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

AVISTA UTILITIES

General

At the end of 2016, Avista Utilities supplied retail electric service to 377,000 customers and retail natural gas service to 340,000 customers across its service territory. Avista Utilities' service territory covers 30,000 square miles with a population of 1.6 million. See "Item 2. Properties" for further information on our utility assets. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Economic Conditions and Utility Load Growth" for information on economic conditions in our service territory.

Electric Operations

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

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

As part of Avista Utilities' resource procurement and management operations in the electric business, we engage in an ongoing process of resource optimization, which involves the economic selection of energy resources from those available to serve our load obligations and the capture of additional economic value through market transactions. We engage in transactions in the wholesale markets by selling and purchasing electric capacity and energy, fuel for electric generation, and derivative instruments related to capacity, energy, fuel and fuel transportation. Such transactions are part of the process of matching available resources with load obligations and hedging the related financial risks. These transactions range from terms of intra-hour up to multiple years. We make continuing projections of:

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

On the basis of these projections, we make purchases and sales of electric capacity and energy, fuel for electric generation, and related derivative instruments to match expected resources to expected electric load requirements and reduce our exposure to electricity (or fuel) market price changes. Resource optimization involves 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.

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. Avista acquires 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 2016 was 1,655 MW, which occurred on December 17, 2016. In 2015, our peak electric native load was 1,638 MW, which occurred during the summer, and in 2014, it was 1,715 MW, which occurred during the winter.

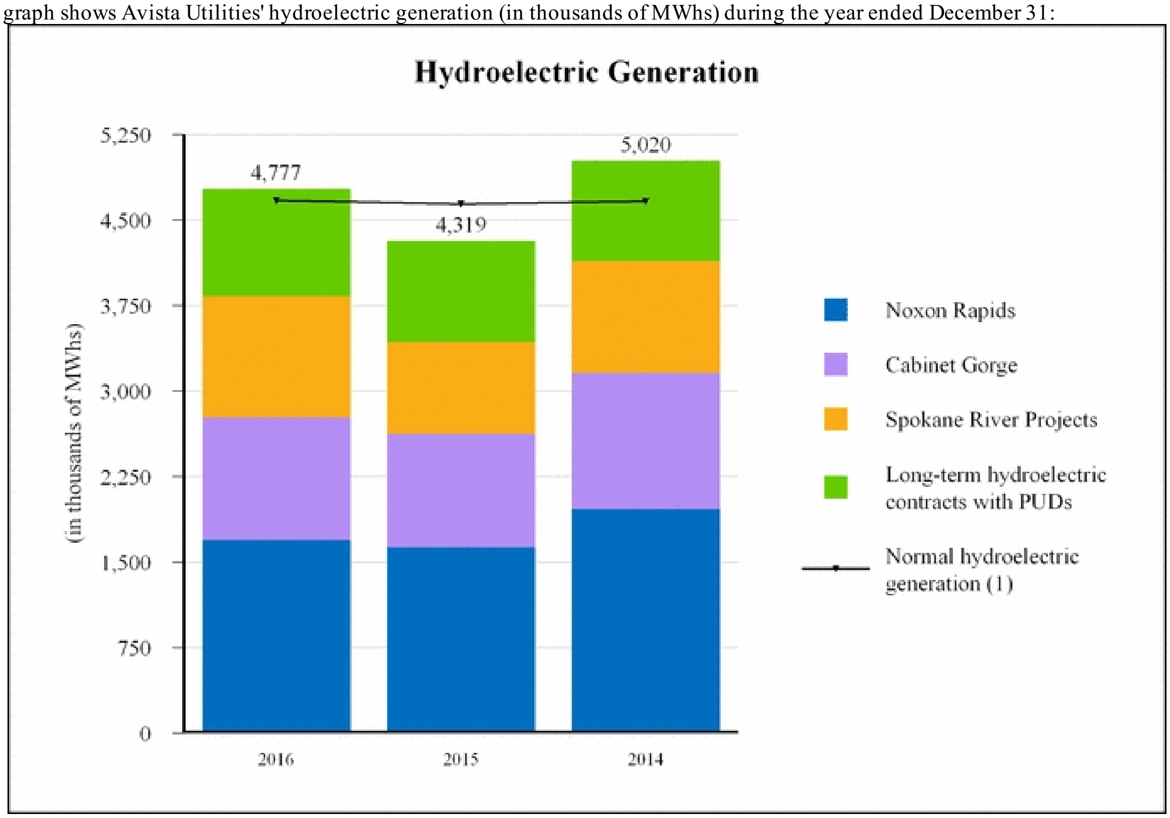
Electric Resources

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.

At the end of 2016, our Company-owned facilities had a total net capability of 1,862 MW, of which 55 percent was hydroelectric and 45 percent was thermal. See “Item 2. Properties” for detailed information on generating facilities.

Hydroelectric Resources Avista Utilities owns and operates six hydroelectric projects on the Spokane River and two hydroelectric projects on the Clark Fork River. Hydroelectric generation is typically our lowest cost source per MWh of electric energy and the availability of hydroelectric generation has a significant effect on total power supply costs. Under normal streamflow and operating conditions, we estimate that we would be able to meet approximately one-half of our total average electric requirements (both retail and long-term wholesale) with the combination of our hydroelectric generation and long-term hydroelectric purchase contracts with certain PUDs in the state of Washington. Our estimate of normal annual hydroelectric generation for 2017 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 538 aMW (or 4.7 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 applying an upstream dam regulation calculation to median natural water flow information. Natural water flow is the flow of the rivers without the influence of dams, whereas regulated water flow takes into account any water flow changes from upstream dams due to releasing or holding back water. The calculation of normal varies annually due to the timing of upstream dam regulation throughout the year.

Thermal Resources Avista Utilities owns the following thermal generating resources:

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

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

Colstrip, which is operated by Talen Energy LLC, is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements in effect through 2019. During 2016, Talen Energy LLC provided notice to the Colstrip owners that it no longer plans to operate units 3 & 4 after May 2018. The Colstrip owners are searching for a replacement operator for units 3 & 4. In addition, see “Item 7. Management's Discussion and Analysis, Environmental Issues and Contingencies" for further discussion regarding environmental issues surrounding Colstrip.

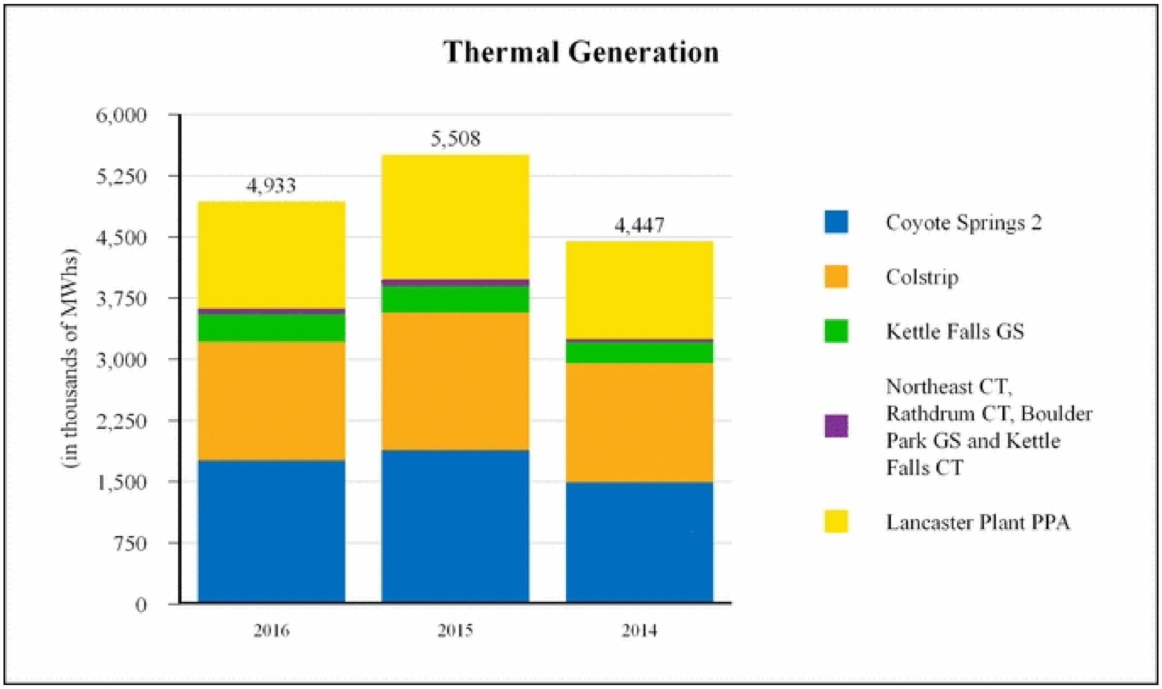
The primary fuel for the Kettle Falls GS is wood waste generated as a by-product and delivered by trucks from forest industry operations within 100 miles of the plant. A combination of long-term contracts and spot purchases has provided, and is expected to meet, fuel requirements for the Kettle Falls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

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

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

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

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



Wind Resources We have exclusive rights to all the capacity of Palouse Wind, a wind generation project developed, owned and managed by an unrelated third-party and located in Whitman County, Washington. We have a PPA that expires in 2042 and allows 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 349,771 MWhs in 2016, 293,563 MWhs in 2015 and 335,291 MWhs in 2014. We have an annual option to purchase the wind project beginning in December 2022. The purchase price per the PPA is a fixed price per KW of in-service capacity with a fixed decline in the price per KW over the remaining 20-year term of the agreement. Under the terms of the PPA, we do not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner.

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

See “Avista Utilities Electric Operating Statistics – Electric Operations” for annual quantities of purchased power, wholesale power sales and power from exchanges in 2016, 2015 and 2014. 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).

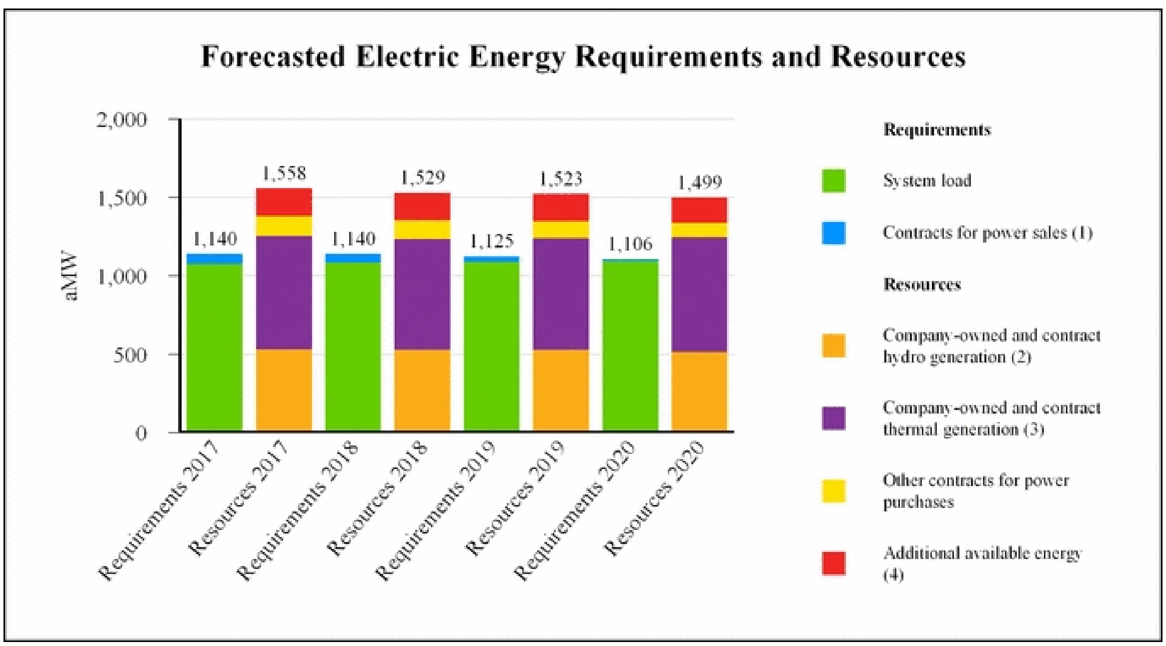
Cabinet Gorge and Noxon Rapids are under one 45-year FERC license issued in March 2001. See “Cabinet Gorge Total Dissolved Gas Abatement Plan” in “Note 19 of the Notes to Consolidated Financial Statements” for discussion of dissolved atmospheric gas levels that exceed state of Idaho and federal numeric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

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

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 1,033 aMW in 2016, 1,047 aMW in 2015 and 1,062 aMW in 2014.

The following graph shows our forecast of our average annual energy requirements and our available resources for 2017 through 2020:



(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) 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 2015, we filed our 2015 Electric IRP with the UTC and the IPUC. The UTC and IPUC review the IRPs and give the public the opportunity to comment. The UTC 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 2015 IRP include the following expectations and projections:

- We will have adequate resources between our owned and contractually controlled generation, combined with conservation and market purchases, to meet customer needs through 2020.
- 565 MW of additional generation capacity is required for the period 2020 through 2034.
- We will meet or exceed the renewable energy requirements of the Washington state Energy Independence Act through the 20-year IRP time frame with a combination of qualifying hydroelectric upgrades, the 30-year PPA with Palouse Wind, the Kettle Falls GS and selective REC purchases.
- Load growth will be approximately 0.6 percent, a decline from the growth of 1.0 percent forecasted in 2013. This delays the need for a new natural gas-fired resource by one year. The decrease in expected load growth is primarily due to energy efficiency programs (using less energy to perform activities) employed by our customers over the next 20 years and the load impacts of increased prices. See "Item 7. Management Discussion and Analysis – Economic Conditions and Utility Load Growth" for further discussion regarding utility customer growth, load growth, and the general economic conditions in our service territory. The estimates of future load growth in the IRP and at "Item 7. Management Discussion and Analysis – Economic Conditions and Utility Load Growth" differ slightly due to the timing of when the two estimates were prepared and due to the time period that each estimate is focused on.
- Colstrip will remain a cost effective and reliable source of power to meet future customer needs.
- Energy efficiency will offset more than half of projected load growth through the 20-year IRP time frame.

Demand response (temporarily reducing the demand for energy) was eliminated from the Preferred Resource Strategy due to higher estimated costs.

We are required to file an IRP every two years, with the next IRP expected to be filed during the third quarter of 2017. Our resource strategy may change from the 2015 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 impacted by legislation for restrictions on GHG 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 UTC and IPUC staff in semi-annual meetings, and updates are given to the OPUC staff quarterly. Other stakeholders, such as the Public Counsel Unit of the Office of the Attorney General or the Citizen Utility Board, are invited to participate. The RMC is provided with an update on plan results and changes in their monthly meetings. These activities provide transparency for the natural gas supply procurement plan. Any material changes to the plan are documented and communicated to RMC members.

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

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

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

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

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

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

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

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

Highlights of the 2016 natural gas IRP include the following expectations and projections:

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

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

Our resource strategy in our 2018 IRP may change from the 2016 IRP based on market, legislative and regulatory developments.

Regulatory Issues

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

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

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

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

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

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

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

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

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

Federal Laws Related to Wholesale Competition

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

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

See “Item 7. Management’s Discussion and Analysis – Competition” for further information.

Regional Transmission Organizations

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

Regional Transmission Planning

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

Regional Energy Markets

The California Independent System Operator (CAISO) recently implemented 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, which could reduce bilateral market liquidity and opportunities for wholesale transactions in the Pacific Northwest. Avista Utilities will continue to monitor the CAISO EIM expansion and the associated impacts. As market fundamentals and our business needs evolve, we will weigh the advantages and disadvantages of joining the CAISO EIM or other organized energy markets in the future.

Reliability Standards

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

The FERC certified the NERC as the single Electric Reliability Organization authorized to establish and enforce reliability standards and delegate authority to regional entities for the purpose of establishing and enforcing reliability standards. The FERC approved the NERC Reliability Standards, including western region standards, making up the set of legally enforceable standards for the United States bulk electric system. The first of these reliability standards became effective in 2007. We are required to self-certify our compliance with these standards on an annual basis and undergo regularly scheduled periodic reviews by the NERC and its regional entity, the Western Electricity Coordinating Council (WECC). Our failure to comply with these standards could result in financial penalties of up to $1 million per day per violation. Annual self-certification and audit processes to date have demonstrated our substantial compliance with these standards. Requirements relating to cyber security are continually evolving. Our compliance with version 5 of the NERC's Critical Infrastructure Protection standard continues to drive several physical security initiatives at our generating stations and substations. We do not expect the costs of these physical security initiatives to have a material impact on our financial results.

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

	Years Ended December 31,		
	2016	2015	2014
ELECTRIC OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 339,210	$ 335,552	$ 338,697
Commercial	305,613	308,210	300,109
Industrial	107,296	111,770	110,775
Public street and highway lighting	7,662	7,277	7,549
Total retail	759,781	762,809	757,130
Wholesale	112,071	127,253	138,162
Sales of fuel	78,334	82,853	83,732
Other	28,492	25,839	27,467
Decoupling	17,349	4,740	—
Provision for earnings sharing	932	(5,621)	(7,503)
Total electric operating revenues	$ 996,959	$ 997,873	$ 998,988
ENERGY SALES (Thousands of MWhs):			
Residential	3,528	3,571	3,694
Commercial	3,183	3,197	3,189
Industrial	1,763	1,812	1,868
Public street and highway lighting	23	23	25
Total retail	8,497	8,603	8,776
Wholesale	2,998	3,145	3,686
Total electric energy sales	11,495	11,748	12,462
ENERGY RESOURCES (Thousands of MWhs):			
Hydro generation (from Company facilities)	3,836	3,434	4,143
Thermal generation (from Company facilities)	3,626	3,983	3,252
Purchased power	4,597	4,899	5,615
Power exchanges	(6)	(2)	(25)
Total power resources	12,053	12,314	12,985
Energy losses and Company use	(558)	(566)	(523)
Total energy resources (net of losses)	11,495	11,748	12,462
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	330,699	327,057	324,188
Commercial	41,785	41,296	40,988
Industrial	1,342	1,353	1,385
Public street and highway lighting	558	529	531
Total electric retail customers	374,384	370,235	367,092
RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (KWh) (1)	10,667	10,827	11,394
Revenue per KWh (in cents)	9.62	9.40	9.17
Annual revenue per customer	$ 1,025.74	$ 1,017.21	$ 1,044.76
AVERAGE HOURLY LOAD (aMW)	1,033	1,047	1,062

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

	Years Ended December 31,		
	2016	2015	2014
RETAIL NATIVE LOAD at time of system peak (MW):			
Winter	1,655	1,529	1,715
Summer	1,587	1,638	1,606
COOLING DEGREE DAYS: (2)			
Spokane, WA			
Actual	474	805	631
Historical average	367	334	394
% of average	129%	241%	160%
HEATING DEGREE DAYS: (3)			
Spokane, WA			
Actual	5,790	5,614	6,215
Historical average	6,482	6,491	6,820
% of average	89%	86%	91%

(1) There has been a trending decline in use per customer during the three-year period primarily due to weather fluctuations but also due in part to energy efficiency measures adopted by customers.

(2) Cooling degree days are the measure of the warmness of weather experienced, based on the extent to which the average of high and low temperatures for a day exceeds 65 degrees Fahrenheit (annual degree days above historic indicate warmer than average temperatures). In 2015, we switched to a rolling 20-year average for calculating cooling degree days, whereas in prior years we used a 30-year rolling average.

(3) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historic indicate warmer than average temperatures). In 2015, we switched to a rolling 20-year average for calculating heating degree days, whereas in prior years we used a 30-year rolling average.

AVISTA UTILITIES NATURAL GAS OPERATING STATISTICS

	Years Ended December 31,		
	2016	2015	2014
NATURAL GAS OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 195,275	$ 193,825	$ 203,373
Commercial	92,978	96,751	103,179
Interruptible	2,179	2,782	2,792
Industrial	3,348	3,792	4,158
Total retail	293,780	297,150	313,502
Wholesale	153,446	204,289	228,187
Transportation	8,339	7,988	7,735
Other	5,787	5,578	7,461
Decoupling	12,309	6,004	—
Provision for earnings sharing	(2,767)	—	(221)
Total natural gas operating revenues	$ 470,894	$ 521,009	$ 556,664
THERMS DELIVERED (Thousands of Therms):			
Residential	186,565	176,613	190,171
Commercial	112,686	107,894	116,748
Interruptible	5,700	4,708	5,033
Industrial	5,234	5,070	5,648
Total retail	310,185	294,285	317,600
Wholesale	684,317	809,132	545,620
Transportation	178,377	164,679	162,311
Interdepartmental and Company use	378	335	411
Total therms delivered	1,173,257	1,268,431	1,025,942
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	300,883	296,005	291,928
Commercial	34,868	34,229	34,047
Interruptible	37	35	37
Industrial	255	261	264
Total natural gas retail customers	336,043	330,530	326,276
RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (therms)	620	593	651
Revenue per therm (in dollars)	$ 1.05	$ 1.10	$ 1.07
Annual revenue per customer	$ 649.01	$ 650.83	$ 696.66
HEATING DEGREE DAYS: (1)			
Spokane, WA			
Actual	5,790	5,614	6,215
Historical average (2)	6,482	6,491	6,820
% of average	89%	86%	91%
Medford, OR			
Actual	3,637	3,534	3,382
Historical average (2)	4,129	4,150	4,539
% of average	88%	85%	75%

(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).

(2) In 2015, we switched to a rolling 20-year average for calculating heating degree days, whereas in prior years we used a 30-year rolling average.

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.

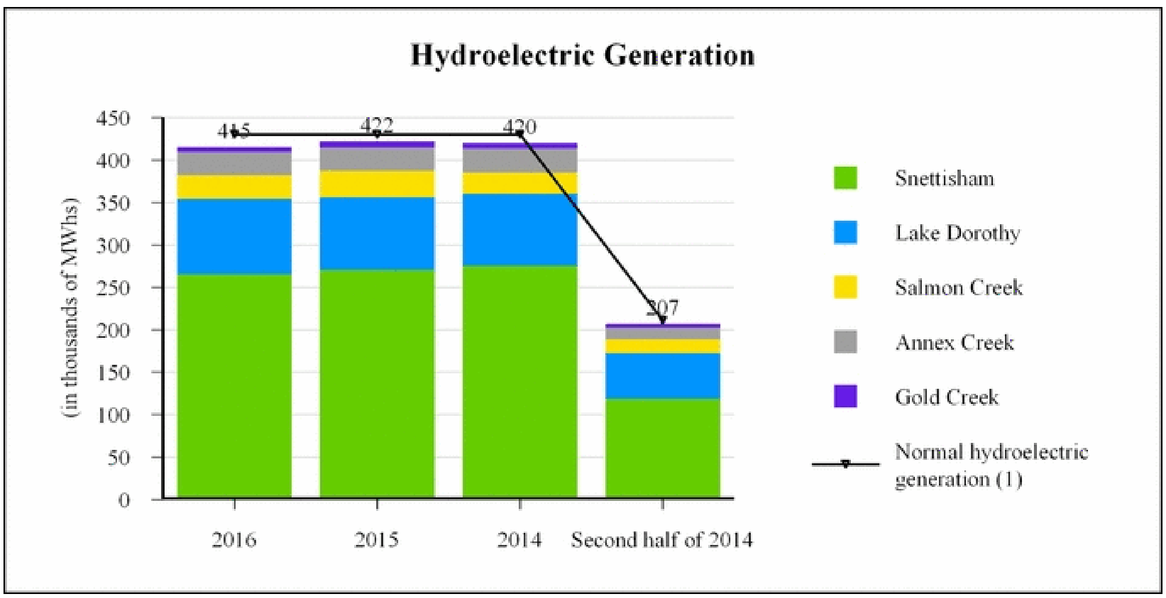
AEL&P owns and operates electric generation, transmission and distribution facilities located in Juneau. AEL&P operates five hydroelectric generation facilities with 102.7 MW of hydroelectric generation capacity as of December 31, 2016. AEL&P owns four of these generation facilities (totaling 24.5 MW 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. 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.

For accounting purposes, this PPA is treated as a capital lease and as of December 31, 2016, the capital lease obligation was $62.2 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, 2016, 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:



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

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

As of December 31, 2016, AEL&P served approximately 17,000 customers. Its primary customers include city, state and federal governmental entities located in Juneau, as well as a mine located in the Juneau area. Most of AEL&P's customers are served on a firm basis while certain of its customers, including its largest customer, are served on an interruptible sales basis. AEL&P maintains separate rate tariffs for each of its customer classes, as well as seasonal rates.

AEL&P's operations are subject to regulation by the RCA with respect to rates, standard of service, facilities, accounting and certain other matters, but not with respect to the issuance of securities. Rate adjustments for AEL&P's customers require approval by the RCA pursuant to RCA regulations. AEL&P filed an electric general rate case during 2016. See "Item 7. Management's Discussion and Analysis – Regulatory Matters" for further discussion of this general rate case filing, including the proposed capital structure.

AEL&P is also subject to the jurisdiction of the FERC concerning the permits and licenses necessary to operate certain of its hydroelectric facilities. One of these licenses (for the Salmon Creek and Annex Creek hydroelectric projects) expires in 2018, but AEL&P plans to extend this license. 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,		Second half of
	2016	2015	2014
ELECTRIC OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 18,207	$ 18,017	$ 8,283
Commercial and government	27,322	26,049	12,948
Public street and highway lighting	266	215	150
Total retail	45,795	44,281	21,381
Other	481	497	263
Total electric operating revenues	$ 46,276	$ 44,778	$ 21,644
ENERGY SALES (Thousands of MWhs):			
Residential	139	139	63
Commercial and government	253	258	125
Public street and highway lighting	1	1	1
Total electric energy sales	393	398	189
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	14,448	14,285	14,121
Commercial and government	2,181	2,179	2,148
Public street and highway lighting	211	210	213
Total electric retail customers	16,840	16,674	16,482
RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (KWh)	9,621	9,730	4,461
Revenue per KWh (in cents)	13.10	12.96	13.15
Annual revenue per customer	$ 1,260.17	$ 1,261.25	$ 586.57
HEATING DEGREE DAYS: (1)			
Juneau, AK			
Actual	7,301	7,395	3,381
Historical average	8,351	8,351	3,721
% of average	87%	89%	91%

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

OTHER BUSINESSES

The following table shows our assets related to our other businesses, excluding intracompany amounts as of December 31, 2016 and 2015 (dollars in thousands):

Entity and Asset Type	2016	2015
Avista Capital		
Salix - wholly owned subsidiary	$ 3,842	$ 2,500
Equity investments	3,000	3,039
Other assets	123	28
Avista Development		
Equity investments	11,530	5,107
Real estate	11,359	6,718
Notes receivable and other assets	5,444	951
METALfx - wholly owned subsidiary	11,568	12,779
Alaska companies (AERC and AJT Mining)	8,390	8,084
Total	$ 55,256	$ 39,206

Avista Capital

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

Avista Development

- Equity investments are primarily in emerging technology venture capital funds and companies, including an investment in a technology company that delivers scalable smart grid solutions to global partners and customers, and a predictive data science company.
- Real estate consists primarily of mixed use commercial and retail office space.
- Notes receivable and other assets are primarily long-term notes receivable made to a company focused on spurring economic development throughout Washington State.
- 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 $4.0 million as of December 31, 2016 and $1.0 million as of December 31, 2015.

Alaska companies

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

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.

Juneau Local Distribution Company (LDC) Project

We continue to evaluate opportunities to grow our presence in Alaska beyond our current AEL&P operations. We have been focused on exploring the viability of building a natural gas LDC in Juneau to bring this energy option to residents. The opportunity has been challenged by difficult economic conditions in Alaska (which are largely caused by low oil prices), relatively low heating oil prices and customer equipment conversion costs. At this time, due to a combination of unfavorable factors, we have suspended our work on this project for the foreseeable future. If conditions change favorably in the future, we may proceed with the regulatory process to request authority to build and operate a gas utility in Juneau.

Salix LNG Project

In early 2016, Salix was selected as the preferred respondent to a request for proposal (RFP) issued by AIDEA that sought a qualified candidate to develop a new LNG facility to serve the Fairbanks, Alaska area as part of the Interior Energy Project (IEP). Commercial discussions in late 2016 led Salix and AIDEA to enter into an agreement that concluded Salix's involvement in the IEP.

ITEM 1A. RISK FACTORS

RISK FACTORS

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

Financial Risk Factors

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

Weather impacts are described in the following subtopics:

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

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

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

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

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

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

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

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, 2016, we had a net interest rate swap derivative liability of $60.9 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, 2016. We may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments. Settlement of interest rate swap derivative instruments in a liability position could require a significant amount of cash, which could negatively impact our liquidity and short-term credit availability and increase interest expense over the term of the associated debt.

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

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

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

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

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

Utility Regulatory Risk Factors

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

Avista Utilities' annual operating expenses and the costs associated with incremental investments in utility assets continue to grow at a faster rate than revenue growth. Our ability to recover these expenses and capital costs depends on the amount and timeliness of retail rate changes allowed by regulatory agencies. We expect to periodically file for rate increases with regulatory agencies to recover our expenses and capital costs and provide an opportunity to earn a reasonable rate of return for shareholders. If regulators do not grant rate increases or grant substantially lower rate increases than our requests in the future or if recovery of deferred expenses is disallowed, it could have a negative effect on our operating revenues, net income and cash flows. During December 2016, the UTC denied our most recent electric and natural gas general rate requests and granted zero rate relief. Pending before the UTC is our petition for reconsideration and alternately for rehearing (Petition) of our 2016 general rate cases to arrive at new electric and natural gas rates. The UTC has provided notice that it expects to rule on the Petition on or before March 16, 2017. If our efforts to obtain rates that are fair, just, reasonable and sufficient are not successful, our 2017 earnings are expected to decrease by $0.20 to $0.30 per diluted share as compared to 2016 actual results. See further discussion 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 change retail rates to reflect current energy prices unless and until we receive regulatory approval,
- customer demand, which is beyond our control because of weather, customer choices, prevailing economic conditions and other factors,
- some of our energy supply cost is fixed by the nature of the energy-producing assets or through contractual arrangements (however, a significant portion of our energy resource costs are not fixed), and

- the potential non-performance by commodity counterparties, which could lead to replacement of the scheduled energy or natural gas at higher prices.

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

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

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

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

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

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

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

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

Operational Risk Factors

We are subject to various operational and event risks.

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

- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, snow and ice storms, which can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies support services and general business operations,
- blackouts or disruptions of interconnected transmission systems (the regional power grid),
- unplanned outages at generating plants,

- fuel cost and availability, including delivery constraints,
- explosions, fires, accidents, or mechanical breakdowns that may occur while operating and maintaining our generation, transmission and distribution systems,
- damage or injuries to third parties caused by our generation, transmission and distribution systems,
- natural disasters that can disrupt energy generation, transmission and distribution, and general business operations, and
- terrorist attacks or other malicious acts that may disrupt or cause damage to our utility assets or the vendors we utilize.

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

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

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

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

Compliance Risk Factors

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

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

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

Actions or limitations to address concerns over the long-term global and our utilities' service area climate changes 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. Such proposals, if adopted, could restrict the operation and raise the costs of our power generation resources as well as the distribution of natural gas to our customers.

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

- increase the operating costs of generating plants,
- increase the lead time and capital costs for the construction of new generating plants,
- require modification of our existing generating plants,

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

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

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

Technology Risk Factors

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

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

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

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

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

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

Strategic Risk Factors

Our strategic business plans, which may be affected by any or all of the foregoing, may change, including the entry into new businesses and/or the exit from existing businesses and the extent of our business development efforts where potential future business is uncertain.

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

- disruptive innovations in the marketplace may outpace our ability to compete or manage our risk,
- potential difficulties in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities,

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

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

ITEM 2. PROPERTIES

AVISTA UTILITIES

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

Our utility electric properties, located in the states of Washington, Idaho, Montana and Oregon, include the following:

Generation Properties

	No. of Units	Nameplate Rating (MW) (1)	Present Capability (MW) (2)
Hydroelectric Generating Stations (River)			
Washington:			
Long Lake (Spokane)	4	70.0	88.0
Little Falls (Spokane)	4	32.0	35.6
Nine Mile (Spokane) (3)	4	36.8	29.0
Upper Falls (Spokane)	1	10.0	10.2
Monroe Street (Spokane)	1	14.8	15.0
Idaho:			
Cabinet Gorge (Clark Fork) (4)	4	265.0	273.0
Post Falls (Spokane)	6	14.8	15.4
Montana:			
Noxon Rapids (Clark Fork)	5	487.8	562.4
Total Hydroelectric		931.2	1,028.6
Thermal Generating Stations (cycle, fuel source)			
Washington:			
Kettle Falls GS (combined-cycle, wood waste) (5)	1	50.7	53.5
Kettle Falls CT (combined-cycle, natural gas) (5)	1	7.2	6.9
Northeast CT (simple-cycle, natural gas)	2	61.8	64.8
Boulder Park GS (simple-cycle, natural gas)	6	24.6	24.6
Idaho:			
Rathdrum CT (simple-cycle, natural gas)	2	166.5	166.5
Montana:			
Colstrip Units 3 & 4 (simple-cycle, coal) (6)	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		1,770.4	1,861.9

(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, 2016.

(3) The project to replace Units 1 and 2 was completed during 2016. The present capability shown is the maximum plant generation we have seen given the water we have had available, because we have not yet had peak water conditions since Units 1 and 2 went into service. As conditions change, we will test plant capability and revise this number accordingly.

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

(5) These generating stations can operate as separate single-cycle plants or combined-cycle with the natural gas plant providing exhaust heat to the wood boiler to increase efficiency.
(6) Jointly owned; data refers to our 15 percent interest.

Electric Distribution and Transmission Plant

Avista Utilities owns and operates approximately 19,000 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of 685 miles of 230 kV line and 1,565 miles of 115 kV line. We also own an 11 percent interest in approximately 500 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana. Our transmission and distribution systems also include numerous substations with transformers, switches, monitoring and metering devices, and other equipment.

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

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

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

Natural Gas Plant

Avista Utilities has natural gas distribution mains of approximately 3,400 miles in Washington, 2,000 miles in Idaho and 2,300 miles in Oregon. We have natural gas transmission mains of approximately 75 miles in Washington and 50 miles in Oregon. Our natural gas system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment.

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

ALASKA ELECTRIC LIGHT AND POWER COMPANY

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

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

Generation Properties and Transmission and Distribution Lines

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

(1) Nameplate rating, also referred to as "installed capacity," is the manufacturer's assigned power capability under specified conditions.
(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2016.
(3) AEL&P does not own this generating facility but has a PPA under which it has the right to purchase, and the obligation to pay for (whether or not energy is received), all of the capacity and energy of this facility. See further information at "Part 1. Item 1. Business – Alaska Electric Light and Power Company."

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

ITEM 3. LEGAL PROCEEDINGS

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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, 2017, there were 8,410 registered shareholders of our common stock.

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

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

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

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

- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements (see "Item 7. Management's Discussion and Analysis - Capital Resources" for compliance with these covenants),
- the hydroelectric licensing requirements of section 10(d) of the FPA (see "Note 1 of Notes to Consolidated Financial Statements"),
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Utilities to maintain a capital structure of no less than 40 percent common equity (inclusive of short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC, and
- 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).

On February 3, 2017, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.3575 per share on the Company's common stock. This was an increase of $0.0150 per share, or 4.4 percent from the previous quarterly dividend of $0.3425 per share.

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

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

	Three Months Ended			
	March 31	June 30	September 30	December 31
2016				
Dividends paid per common share	$ 0.3425	$ 0.3425	$ 0.3425	$ 0.3425
Trading price range per common share:				
High	$ 41.12	$ 44.80	$ 44.97	$ 42.63
Low	$ 34.67	$ 38.70	$ 40.43	$ 39.11
2015				
Dividends paid per common share	$ 0.33	$ 0.33	$ 0.33	$ 0.33
Trading price range per common share:				
High	$ 38.30	$ 34.25	$ 33.99	$ 36.06
Low	$ 32.22	$ 30.41	$ 29.93	$ 32.86

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,				
	2016	2015	2014	2013	2012
Operating Revenues:					
Avista Utilities	$ 1,372,638	$ 1,411,863	$ 1,413,499	$ 1,403,995	$ 1,354,185
AEL&P	46,276	44,778	21,644	—	—
Other	23,569	28,685	39,219	39,549	38,953
Intersegment eliminations	—	(550)	(1,800)	(1,800)	(1,800)
Total	$ 1,442,483	$ 1,484,776	$ 1,472,562	$ 1,441,744	$ 1,391,338
Income (Loss) from Operations (pre-tax):					
Avista Utilities	$ 277,070	$ 241,228	$ 239,976	$ 232,572	$ 188,778
AEL&P	15,434	14,072	6,221	—	—
Other	(2,701)	(2,086)	6,391	(1,483)	(1,680)
Total	$ 289,803	$ 253,214	$ 252,588	$ 231,089	$ 187,098
Net income from continuing operations	$ 137,316	$ 118,170	$ 119,866	$ 104,333	$ 76,803
Net income from discontinued operations	—	5,147	72,411	7,961	1,997
Net income	$ 137,316	$ 123,317	$ 192,277	$ 112,294	$ 78,800
Net income attributable to noncontrolling interests	$ (88)	$ (90)	$ (236)	$ (1,217)	$ (590)
Net Income (Loss) attributable to Avista Corporation shareholders:					
Avista Utilities	$ 132,490	$ 113,360	$ 113,263	$ 108,598	$ 81,704
AEL&P	7,968	6,641	3,152	—	—
Ecova - Discontinued operations	—	5,147	72,390	7,129	1,825
Other	(3,230)	(1,921)	3,236	(4,650)	(5,319)
Net income attributable to Avista Corp. shareholders	$ 137,228	$ 123,227	$ 192,041	$ 111,077	$ 78,210
Average common shares outstanding, basic	63,508	62,301	61,632	59,960	59,028
Average common shares outstanding, diluted	63,920	62,708	61,887	59,997	59,201
Common shares outstanding at year-end	64,188	62,313	62,243	60,077	59,813
Earnings per common share attributable to Avista Corp. shareholders, basic:					
Earnings per common share from continuing operations	$ 2.16	$ 1.90	$ 1.94	$ 1.74	$ 1.30
Earnings per common share from discontinued operations	—	0.08	1.18	0.11	0.02
Total earnings per common share attributable to Avista Corp. shareholders, basic	$ 2.16	$ 1.98	$ 3.12	$ 1.85	$ 1.32
Earnings per common share attributable to Avista Corp. shareholders, diluted:					
Earnings per common share from continuing operations	$ 2.15	$ 1.89	$ 1.93	$ 1.74	$ 1.30
Earnings per common share from discontinued operations	—	0.08	1.17	0.11	0.02
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 2.15	$ 1.97	$ 3.10	$ 1.85	$ 1.32

(in thousands, except per share data and ratios)	Years Ended December 31,				
	2016	2015	2014	2013	2012
Dividends declared per common share	$ 1.37	$ 1.32	$ 1.27	$ 1.22	$ 1.16
Book value per common share	$ 25.69	$ 24.53	$ 23.84	$ 21.61	$ 21.06
Total Assets at Year-End:					
Avista Utilities	$ 4,975,555	$ 4,601,708	$ 4,357,760	$ 3,930,251	$ 3,883,602
AEL&P	273,770	265,735	263,070	—	—
Other	60,430	39,206	80,141	81,282	95,638
Total (1)	$ 5,309,755	$ 4,906,649	$ 4,700,971	$ 4,011,533	$ 3,979,240
Long-Term Debt and Capital Leases (including current portion)	$ 1,682,004	$ 1,573,278	$ 1,487,126	$ 1,262,036	$ 1,217,520
Nonrecourse Long-Term Debt of Spokane Energy (including current portion)	$ —	$ —	$ 1,431	$ 17,838	$ 32,803
Long-Term Debt to Affiliated Trusts	$ 51,547	$ 51,547	$ 51,547	$ 51,547	$ 51,547
Total Avista Corp. Shareholders' Equity	$ 1,648,727	$ 1,528,626	$ 1,483,671	$ 1,298,266	$ 1,259,477
Ratio of Earnings to Fixed Charges (2)	3.32	3.13	3.39	3.02	2.48

(1) The total assets at year-end for the years 2013 and 2012 exclude the total assets associated with Ecova of $339.6 million and $322.7 million, respectively.

(2) See Exhibit 12 for computations.

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

Business Segments

As of December 31, 2016, 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):

	2016	2015	2014
Avista Utilities	$ 132,490	$ 113,360	$ 113,263
AEL&P	7,968	6,641	3,152
Ecova - Discontinued operations (1)	—	5,147	72,390
Other	(3,230)	(1,921)	3,236
Net income attributable to Avista Corporation shareholders	$ 137,228	$ 123,227	$ 192,041

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

Executive Level Summary

Overall Results

Net income attributable to Avista Corp. shareholders was $137.2 million for 2016, an increase from $123.2 million for 2015. Avista Utilities' earnings increased primarily due to an increase in electric and natural gas gross margin as a result of general rate increases and the implementation of decoupling mechanisms in Idaho and Oregon. See "Results of Operations – Avista Utilities – Non-GAAP Financial Measures" for further discussion of gross margin. Also, there was a reduction in the electric provision for earnings sharing (which is an offset to revenue). Retail electric loads decreased as compared to prior year and retail natural gas loads increased as compared to prior year, but the impact of changes in load as compared to normal for electric and natural gas was mostly offset by decoupling mechanisms.

In addition to the fluctuations in gross margin, there were increases in other operating expenses, depreciation, and interest expense. There was also an increase in earnings at AEL&P offset by an increase in the net loss at the other businesses.

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

2016 Washington General Rate Cases

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

In December 2016, we filed a Petition for Reconsideration or, in the alternative, Rehearing (Petition) with the UTC. The UTC provided notice inviting parties to respond to our Petition, stating that it expects to rule on the Petition on or before March 16, 2017. If our efforts to obtain rates that are fair, just, reasonable and sufficient are not successful, our 2017 earnings will suffer a significant adverse impact. We believe the UTC order will not allow us to earn a reasonable return on investments that we have already made in our infrastructure. In addition, the order will provide no opportunity for us to earn the return on equity authorized by the UTC or a fair return for shareholders. In the order, the UTC did not specifically disallow any of our capital projects, and we continue to believe these investments are necessary and will be recoverable in rates in the future.

In 2017, we expect our operating costs to continue to grow along the same trend we have been experiencing recently; however, if our current Washington rates remain in effect, we expect to earn below our currently authorized return on equity (ROE). The order will result in regulatory lag, and, accordingly, we expect to experience earnings contraction in 2017 of $0.20 to $0.30 per diluted share as compared to 2016 actual results.

See "Item 7. Management's Discussion and Analysis – Regulatory Matters" for additional discussion surrounding this general rate case and all of our other outstanding general rate cases.

Alaska Energy and Resources Company Acquisition

On July 1, 2014, we acquired AERC, based in Juneau, Alaska. The completion of this transaction limits the comparability of the financial results for 2016 and 2015 to those for 2014 since the first half of 2014 does not contain any financial results from AERC. This transaction resulted in the recording of $52.4 million in goodwill. For additional information regarding the AERC transaction, including pro forma financial comparisons, see “Note 4 of the Notes to Consolidated Financial Statements.”

Ecova Disposition

On June 30, 2014, Avista Capital completed the sale of its interest in Ecova for a sales price of $335.0 million in cash, less the payment of debt and other customary closing adjustments. The sale of Ecova provided total cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.7 million and resulted in a net gain of $74.8 million. Most of the net gain was recognized in 2014 with some minor true-ups during 2015.

The completion of this transaction limits the comparability of the financial results for 2016 and 2015 to those for 2014 since the first half of 2014 contains the financial results of Ecova (in discontinued operations) and 2015 and 2016 do not have any material results from Ecova. For additional information regarding the Ecova disposition, see “Note 5 of the Notes to Consolidated 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

2014 General Rate Cases

In November 2014, the UTC approved an all-party settlement agreement related to our electric and natural gas general rate cases filed in February 2014 and new rates became effective on January 1, 2015. The settlement was designed to increase annual electric base revenues by $12.3 million, or 2.5 percent. The settlement was designed to increase annual natural gas base revenues by $8.5 million, or 5.6 percent. The settlement agreement also included the implementation of decoupling mechanisms for electric and natural gas and a related after-the-fact earnings test. See "Decoupling and Earnings Sharing Mechanisms" below for further discussion of these mechanisms.

Specific capital structure ratios and the cost of capital components were not agreed to in the settlement agreement. The revenue increases in the settlement were not tied to the 7.32 percent rate of return on rate base (ROR) used in conjunction with the after-the fact earnings test discussed under "Decoupling and Earnings Sharing Mechanisms" below. The electric and natural gas revenue increases were negotiated numbers, with each party using its own set of assumptions underlying its agreement to the revenue increases. The parties agreed that the 7.32 percent ROR will be used to calculate the AFUDC and will be used for other purposes.

2015 General Rate Cases

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

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

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

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

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

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

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

PC Petition for Judicial Review

On March 18, 2016, PC filed in Thurston County Superior Court a Petition for Judicial Review of the UTC's Order 05 and Order 06 described above that concluded our 2015 electric and natural gas general rate cases. In its Petition for Judicial Review, PC seeks judicial review of five aspects of Order 05 and Order 06, alleging, among other things, that (1) the UTC exceeded its statutory authority by setting rates for our natural gas and electric services based on amounts for utility plant and facilities that are not "used and useful" in providing utility service to customers; (2) the UTC acted arbitrarily and capriciously in granting an attrition adjustment for our electric operations after finding that the we did not meet the newly articulated standard regarding attrition adjustments; (3) the UTC erred in applying the "end results test" to set rates for our electric operations that are not supported by the record; (4) the UTC did not correct its calculation of our electric rates after significant errors were brought to its attention; and (5) the UTC's calculation of our electric rates lacks substantial evidence.

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

On April 18, 2016, PC filed an application with the Thurston County Superior Court to certify this matter for review directly by the Court of Appeals, an intermediate appellate court in the State of Washington. After briefing and argument, the matter was certified on April 29, 2016 and accepted by the Court of Appeals on July 29, 2016. The parties are providing briefs to the Court, after which the Court will set the matter for argument. A decision from the Court is not expected until late 2017, at the earliest.

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

2016 General Rate Cases

On December 15, 2016, the UTC issued an order related to our Washington electric and natural gas general rate cases that were originally filed with the UTC in February 2016. The UTC order denied the Company's proposed electric and natural gas rate increase requests of $38.6 million and $4.4 million, respectively. Accordingly, our current electric and natural gas retail rates will remain unchanged in Washington State.

Our original requests were based on a proposed ROR of 7.64 percent with a common equity ratio of 48.5 percent and a 9.9 percent ROE.

On December 23, 2016 we filed a Petition for Reconsideration or, in the alternative, Rehearing (Petition) with the UTC related to our 2016 general rate cases.

The UTC’s Order and Avista Corp.’s Response

The primary reason given by the UTC in reaching its conclusion is 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. Further, the order states that, among other things, we did not demonstrate, as a necessary condition to being allowed an attrition adjustment, that we have suffered from chronic under-earning caused by circumstances beyond our ability to control. We disagree with the UTC as to various questions of fact and law.

In support of its decision, the UTC stated that we did not demonstrate that our current revenue is insufficient for covering costs and providing the opportunity to earn a reasonable return during the 2017 rate period. The UTC also stated that we did not demonstrate that our capital expenditures and increased operating costs are both necessary and immediate.

Our Petition responding to the UTC's order points to evidence in the case that demonstrates, contrary to the UTC’s findings, the following:

- Current retail rates are not sufficient for the 2017 rate period, and therefore a revenue increase is necessary. In previously filed testimony, UTC Staff agreed that current rates were not sufficient.
- The costs associated with the growth in rate base and operating expenses are growing at a faster pace than revenue from retail sales, and therefore a revenue adjustment is necessary to close this gap. The revenue adjustment to close this gap is sometimes called an attrition adjustment. In previously filed testimony, UTC Staff agreed that a revenue adjustment is necessary to close this gap.
- All of the capital projects and operating expenses we included in the case are necessary in the time frame proposed in order for us to continue to provide safe, reliable service to customers. No party in the case identified a single capital project that should not be completed in the time frame we proposed (other than Public Counsel’s general opposition to AMI).
- We presented all of the studies and analyses in this case, consistent with our previous filings with the UTC, and the UTC Staff acknowledged in previously filed testimony, that we provided such studies.
- We earned close to our allowed return on equity during each of the years 2013 through 2015, and into 2016. This opportunity was possible only with the revenue increases related to attrition adjustments, and an attrition adjustment is also necessary for 2017.

In previously filed testimony, the UTC Staff supported electric and natural gas revenue increases totaling $28.4 million. Commissioner Jones dissented and did not support the decision. In his dissent, Commissioner Jones supported an electric revenue increase of $26.0 million, and a natural gas increase of $2.4 million, based on UTC Staff's analysis.

In response to our Petition, on December 27, 2016 the UTC issued a “Notice of Opportunity to File Answers to Petition for Reconsideration or Rehearing.” In its Notice the UTC requested parties to the case to file written answers to our Petition and all interested parties filed written answers to the Petition in January 2017. The UTC's notice indicated that it expects to enter an order resolving the Petition no later than March 16, 2017.

In UTC Staff’s Answer to our Petition, UTC Staff essentially abandoned its previous recommendations to the UTC, and supported no electric and natural gas revenue increases. In our Motion to Respond, and Response Comments, to the Answers of the parties, filed January 20, 2017, we noted the inappropriateness of UTC Staff’s changed position, which was without any basis in new or changed facts or circumstances. The other parties generally supported the UTC decision in their Answers to our Petition.

Future General Rate Case Filings

We plan to file new electric and natural gas general rate cases in Washington in the second quarter of 2017. We will address the issues raised by the UTC in the most recent rate order, including, but not limited to, multi-year rate plans to address the concerns over frequency of filings, the necessity of an attrition adjustment for the opportunity to earn our allowed return in a period when growth rates in investment in plant and operating expenses outpace growth in energy sales, and whether our current spending levels are both necessary and immediate to provide safe and reliable service to our customers.

We may also seek an order from the UTC allowing for the deferral for later recovery of ongoing costs associated with AMI.

Accounting Order to Defer Existing Washington Electric Meters

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

The prudence of the overall AMI project and ultimate recovery of the regulatory assets and the costs of the new meters will be addressed in a future regulatory proceeding. The undepreciated value estimated for the existing meters is approximately $19.1 million. For ratemaking purposes, the existing electric meters won't be recorded as regulatory assets until they are physically removed from service, but for GAAP purposes, they are regulatory assets upon the commitment by management to retire the meters.

Idaho General Rate Cases

2015 General Rate Cases

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

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

The settlement agreement also reflects the following:

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

2016 General Rate Cases

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

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

In addition to the agreed upon increase in electric revenues to recover costs primarily driven by our increased capital investments in infrastructure to serve customers, the settlement agreement includes the continued recovery of approximately $4.1 million in costs related to the Palouse Wind Project through the PCA mechanism rather than through base rates.

In our original request we requested an overall increase in base electric rates of 6.3 percent (designed to increase annual electric revenues by $15.4 million), effective January 1, 2017.

Our original request was based on a proposed ROR of 7.78 percent with a common equity ratio of 50 percent and a 9.9 percent ROE.

Oregon General Rate Cases

2013 General Rate Case

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

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

The approved settlement agreement provided an authorized ROR of 7.47 percent, with a common equity ratio of 48 percent and a 9.65 percent ROE.

2014 General Rate Case

In March 2015, we filed an all-party settlement agreement with the OPUC related to our natural gas general rate case, which was originally filed in September 2014. The settlement agreement was designed to increase base natural gas revenues by $5.3 million. Included in this base rate increase is $0.3 million in base revenues that we were already receiving from customers through a separate rate adjustment. Therefore, the net increase in base revenues was $5.0 million, or 4.9 percent on a billed basis. The parties requested that new retail rates become effective on April 16, 2015. On April 9, 2015, the OPUC issued an Order approving the settlement agreement as filed.

This settlement agreement provided for an overall authorized ROR of 7.516 percent with a common equity ratio of 51 percent and a 9.5 percent ROE.

2015 General Rate Case

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

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

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

2016 General Rate Case

On November 30, 2016 we filed a natural gas general rate case with the OPUC. We have requested an overall increase in base natural gas rates of 14.5 percent (designed to increase annual natural gas revenues by $8.5 million). Our request is based on a proposed ROR of 7.83 percent with a common equity ratio of 50 percent and a 9.9 percent ROE. The OPUC has up to 10 months to review our request and issue a decision.

Alaska Electric Light and Power Company

Alaska General Rate Case

In September 2016, AEL&P filed an electric general rate case with the RCA. AEL&P was granted a refundable interim base rate increase of 3.86 percent (designed to increase electric revenues by $1.3 million), that took effect in November 2016.

AEL&P has also requested a permanent base rate increase of an additional 4.24 percent (designed to increase electric revenues by $1.5 million), which, if approved, could take effect in February 2018. This represents a combined total rate increase of 8.1 percent (designed to increase electric revenues by $2.8 million).

Included in the general rate case are additional annual revenues of $2.9 million from the Greens Creek Mine, which offsets a portion of the rate increase to retail customers that would otherwise occur.

The RCA must rule on permanent rate increase requests within 450 days (approximately 15 months) from the date of filing, unless otherwise extended by consent of the parties. The statutory timeline for the AEL&P GRC, with the consent of the parties, has been extended to February 8, 2018.

The rate request is based largely on the addition of a new backup generation plant (Industrial Blvd. Plant) to rate base.

Avista Utilities

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to Avista Utilities' customers with no change in gross margin (operating revenues less resource costs) or net income. In Oregon, we absorb (cost or benefit) 10 percent of the difference between actual and projected natural gas costs included in retail rates for supply that is not hedged. Total net deferred natural gas costs among all jurisdictions were a liability of $30.8 million as of December 31, 2016 and a liability of $17.9 million as of December 31, 2015, and these deferred natural gas costs balances represent amounts due to customers.

The following PGAs went into effect in our various jurisdictions during 2014, 2015 and 2016:

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	November 1, 2014	1.2%
	November 1, 2015	(15.0)%
	November 1, 2016	(8.0)%
Idaho	November 1, 2014	(2.1)%
	November 1, 2015	(14.5)%
	November 1, 2016	(7.8)%
Oregon	November 1, 2014	8.3%
	November 1, 2015	(14.1)%
	November 1, 2016	(6.0)%

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between Avista Utilities' actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers. Total net deferred power costs under the ERM were a liability of $21.3 million as of December 31, 2016 compared to a liability $18.0 million as of December 31, 2015, and these deferred power cost balances represent amounts due to customers.

The difference in net power supply costs under the ERM primarily results from changes in:

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

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

The following is a summary of the ERM:

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

Under the ERM, Avista Utilities makes an annual filing on or before April 1 of each year to provide the opportunity for the UTC staff and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. We made our annual filing on March 31, 2016. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by UTC order. The 2015 ERM deferred power costs transactions were approved by an order from the UTC.

Avista Utilities has a PCA mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $2.2 million as of December 31, 2016 compared to an asset of $0.2 million as of December 31, 2015.

Decoupling and Earnings Sharing Mechanisms

Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Utilities' jurisdictions, each month Avista Utilities' electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes, rather than kilowatt hour and therm sales. The difference between revenues based on the number of customers and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year.

Washington Decoupling and Earnings Sharing

In Washington, the UTC approved our decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to 3 percent on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

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

- If we have a decoupling rebate balance for the prior year and earn in excess of the authorized ROR (7.32 percent for 2015 and 7.29 percent for 2016), the rebate to customers would be increased by 50 percent of the earnings in excess of the authorized ROR.
- If we have a decoupling rebate balance for the prior year and our earnings are equal to or less than the authorized ROR, only the base amount of the rebate to customers would be made.
- If we have a decoupling surcharge balance for the prior year and earn in excess of the authorized ROR, the surcharge to customers would be reduced by 50 percent of the earnings in excess of the authorized ROR (or eliminated). If 50 percent of the earnings in excess of the authorized ROR exceeds the decoupling surcharge balance, the dollar amount that exceeds the surcharge balance would create a rebate balance for customers.
- If we have a decoupling surcharge balance for the prior year and our earnings are equal to or less than the authorized ROR, the base amount of the surcharge to customers would be made.

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

Idaho FCA and Earnings Sharing Mechanisms

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

For the period 2013 through 2015, we had an after-the-fact earnings test, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earned more than a 9.8 percent ROE, we were required to share with customers 50 percent of any earnings above the 9.8 percent. There was no provision for a surcharge to customers if our ROE was less than 9.8 percent. This after-the-fact earnings test was discontinued as part of the settlement of our 2015 Idaho electric and natural gas general rates cases (discussed in further detail above).

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

Oregon Decoupling Mechanism

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

Cumulative Decoupling and Earnings Sharing Mechanism Balances

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

	December 31, 2016	December 31, 2015
Washington		
Decoupling surcharge	$ 30,408	$ 10,933
Provision for earnings sharing rebate	(5,113)	(3,422)
Idaho		
Decoupling surcharge	$ 8,292	n/a
Provision for earnings sharing rebate	(5,184)	(8,814)
Oregon		
Decoupling surcharge	$ 2,021	n/a
Provision for earnings sharing rebate	—	—

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

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

Results of Operations - Overall

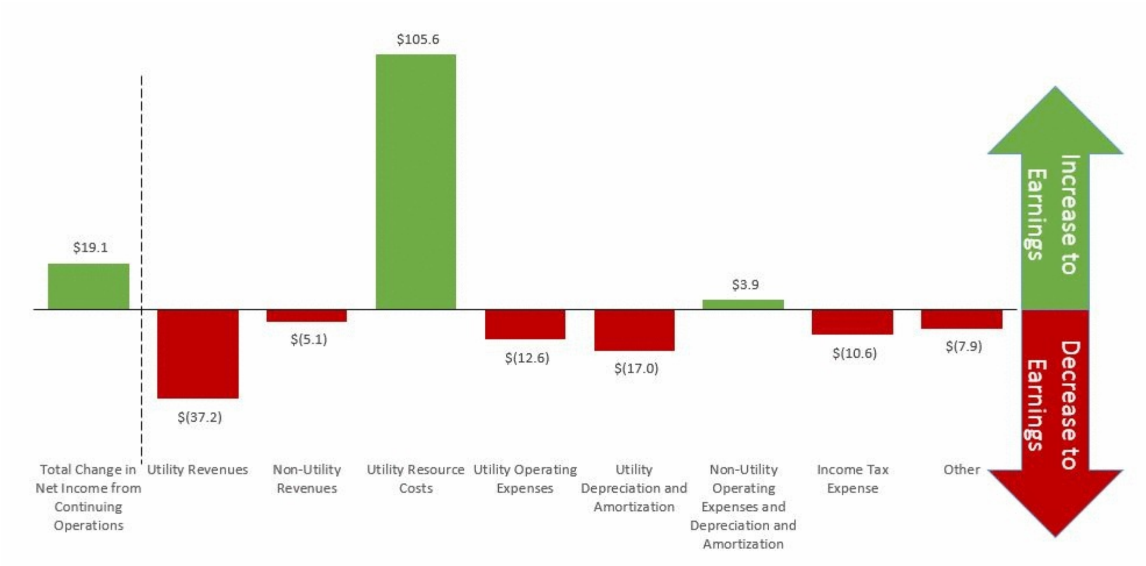
The following provides an overview of changes in our Consolidated Statements of Income. More detailed explanations are provided, particularly for operating revenues and operating expenses, in the business segment discussions (Avista Utilities, AEL&P, Ecova - Discontinued Operations and the other businesses)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

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

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

2016 compared to 2015

The following graph shows the total change in net income from continuing operations for the year ended December 31, 2015 to the year ended December 31, 2016, as well as the various factors that caused such change (dollars in millions):



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

Non-utility revenues decreased due to the long-term fixed rate electric capacity contract that was previously held by Spokane Energy being transferred to Avista Corp. during the second quarter of 2015. The capacity revenue from this contract was included in non-utility revenues when it was held by Spokane Energy during the first quarter of 2015. After the transfer, the revenue is included in Avista Utilities' revenues. The contract expired during December 2016.

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

Utility operating expenses increased due to an increase at Avista Utilities and a slight increase at AEL&P. Avista Utilities' portion of other operating expenses increased due to an increase in medical costs of $3.0 million, electric generation operating and maintenance expenses of $6.8 million, natural gas distribution expenses of $2.2 million and other postretirement benefit expenses of $2.0 million.

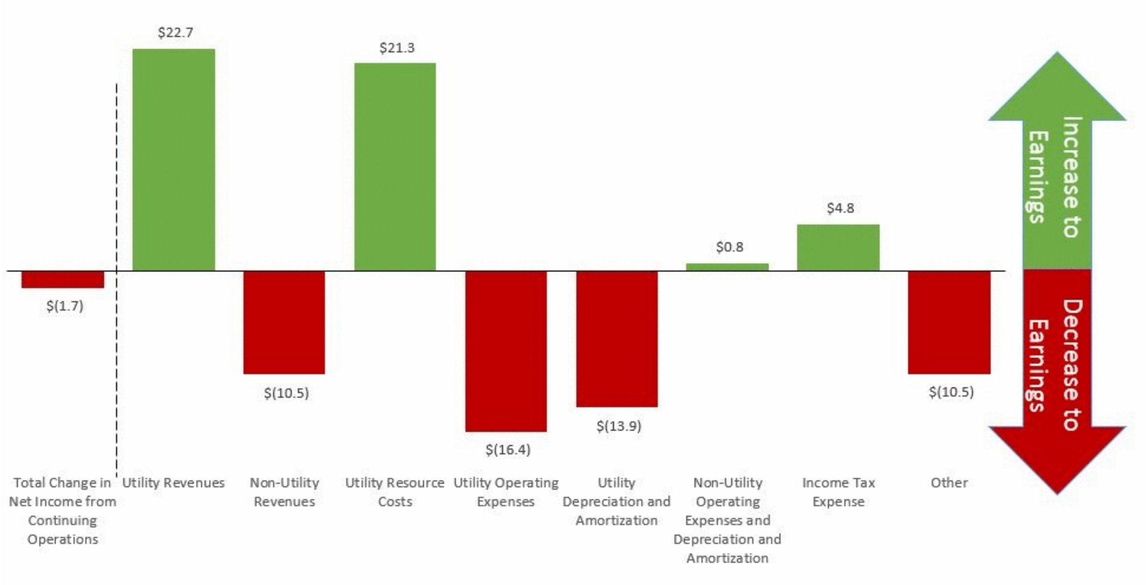
Utility depreciation and amortization increased $17.0 million driven by additions to utility plant.

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

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

2015 compared to 2014

The following graph shows the total change in net income from continuing operations for the year ended December 31, 2014 to the year ended December 31, 2015, 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 $23.1 million due to a full year of AEL&P results in 2015 as compared to six months in 2014. Avista Utilities' electric revenues decreased due to lower loads from warmer weather, which were partially offset by the decoupling mechanism in Washington, a general rate increase in Washington and a decrease in the provision for earnings sharing (which is an offset to revenue). Avista Utilities' natural gas revenues decreased due to lower heating loads from significantly warmer weather that was partially offset by the decoupling mechanism in Washington and general rate increases.

Other non-utility revenues decreased primarily due to the long-term fixed rate electric capacity contract that was previously held by Spokane Energy being transferred to Avista Corp. during the second quarter of 2015. The capacity revenue from this contract was included in non-utility revenues when it was held by Spokane Energy. After the transfer, the revenue is included in Avista Utilities' revenues.

Utility resource costs decreased due to a decrease at Avista Utilities, partially offset by an increase at AEL&P. AEL&P's resource costs increased $6.1 million due to a full year of AEL&P results in 2015 as compared to six months in 2014. Avista Utilities' electric resource costs decreased primarily due to a decrease in purchased power (from lower volumes purchased, partially offset by higher wholesale prices) and a decrease in other fuel costs. Natural gas resource costs decreased due to a decrease in natural gas purchased resulting from lower prices, partially offset by higher volumes.

Utility operating expenses increased due to an increase at Avista Utilities and at AEL&P. Avista Utilities' portion of other operating expenses increased $11.1 million and AEL&P's other operating expenses increased $5.3 million due to a full year of AEL&P results in 2015 as compared to six months in 2014. Avista Utilities incurred increased generation, transmission and distribution operating expenses of $5.7 million, increased administrative and general wages of $9.8 million and increased pension and other post-retirement benefit expenses of $10.0 million. In addition, Avista Utilities incurred incremental storm restoration costs associated with the November 2015 wind storm of approximately $2.9 million. These increases were partially offset by decreases in outside services and generation maintenance of $7.8 million.

Utility depreciation and amortization increased due to additions to utility plant and the inclusion of a full year of AEL&P depreciation as compared to only six months of AEL&P in 2014.

Income tax expense decreased and our effective tax rate was 36.3 percent for 2015 compared to 37.6 percent for 2014. The decrease in expense was primarily due to a decrease in income before income taxes.

Other was primarily related to an increase in interest expense, due to additional debt being outstanding during 2015 as compared to 2014. Also, there were losses on investments at our subsidiaries.

Non-GAAP Financial Measures

The following discussion for Avista Utilities includes two financial measures that are considered “non-GAAP financial measures,” electric gross margin and natural gas gross margin. In the AEL&P section, we include a discussion of electric gross margin, which is also a non-GAAP financial measure.

Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included (excluded) in the most directly comparable measure calculated and presented in accordance with GAAP. The presentation of electric gross margin and natural gas gross margin is intended to supplement an understanding of operating performance. We use these measures to determine whether the appropriate amount of revenue is being collected from our customers to allow for the recovery of energy resource costs and operating costs, as well as to analyze how changes in loads (due to weather, economic or other conditions), rates, supply costs and other factors impact our results of operations. In addition, we present electric and natural gas gross margin separately below for Avista Utilities since each business has different cost sources, cost recovery mechanisms and jurisdictions, such that separate analysis is beneficial. These measures are not intended to replace income from operations as determined in accordance with GAAP as an indicator of operating performance. The calculations of electric and natural gas gross margins are presented below.

Results of Operations - Avista Utilities

2016 compared to 2015

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

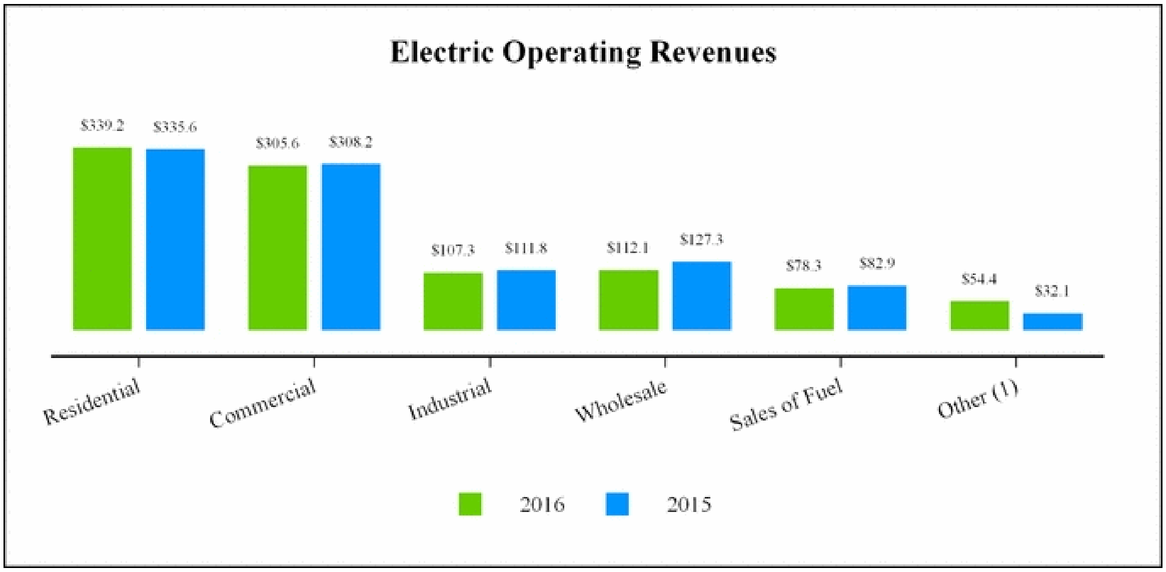
	Electric		Natural Gas		Intracompany		Total	
	2016	2015	2016	2015	2016	2015	2016	2015
Operating revenues	$ 996,959	$ 997,873	$ 470,894	$ 521,010	$ (95,215)	$ (107,020)	$ 1,372,638	$ 1,411,863
Resource costs	360,591	400,910	273,976	351,101	(95,215)	(107,020)	539,352	644,991
Gross margin	$ 636,368	$ 596,963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

The gross margin on electric sales increased $39.4 million and the gross margin on natural gas sales increased $27.0 million. The increase in electric gross margin was primarily due to general rate increases, lower resource costs, the implementation of decoupling in Idaho and a $6.6 million decrease in the provision for earnings sharing (which is an offset to revenue), partially offset by lower electric loads. The weather was warmer than the prior year in April and May (which decreased electric heating loads) and cooler than the prior year June through August (which decreased electric cooling loads). This was partially offset by the effect of weather that was cooler than the prior year in the first and fourth quarters (which increased electric heating loads). Overall, weather was warmer than normal for most of the year. Retail electric loads decreased as compared to prior year and the impact as compared to normal was mostly offset by decoupling mechanisms. See the table below for a comparison of the amounts recorded for decoupling by jurisdiction. For 2016, we recognized a pre-tax benefit of $5.1 million under the ERM in Washington compared to a benefit of $6.3 million for 2015.

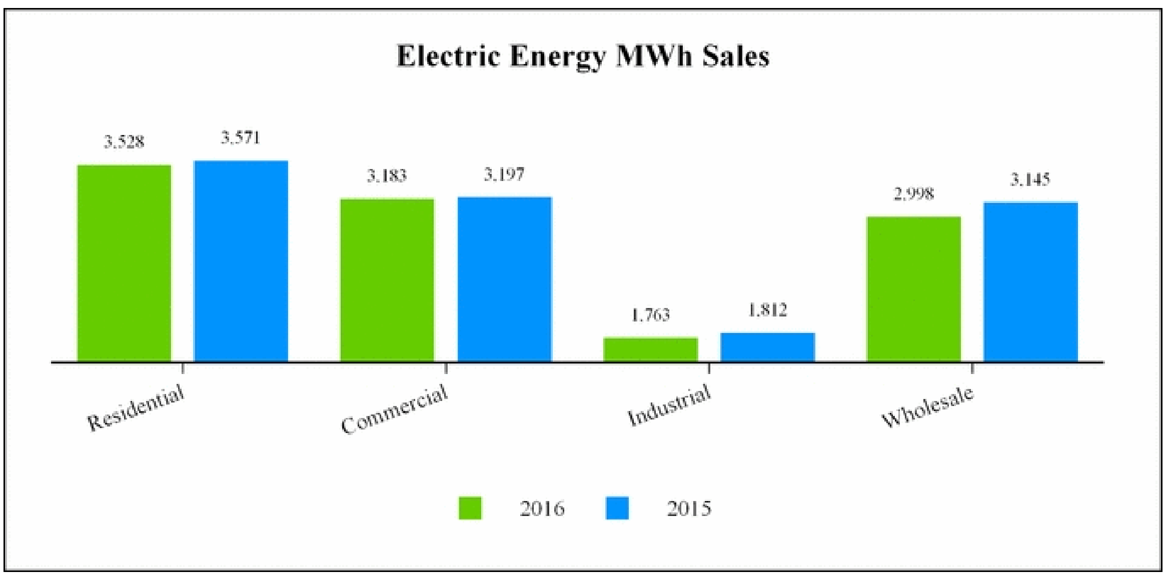
The increase in natural gas gross margin was primarily due to general rate increases in each of our jurisdictions, lower natural gas resources costs, the implementation of decoupling mechanisms in Idaho and Oregon, and higher natural gas retail loads. Weather was cooler in the first quarter (which increased natural gas heating loads), warmer in April and May (which reduced natural gas heating loads) and cooler in the fourth quarter (which increased natural gas heating loads) as compared to the prior year. The period June through September typically does not have significant natural gas retail loads. Overall, retail natural gas loads increased as compared to prior year and the impact as compared to normal (lower loads) was mostly offset by decoupling mechanisms. See the table below for a comparison of the amounts recorded for decoupling by jurisdiction.

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

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



(1) Other electric revenues in the graph above includes public street and highway lighting, which is considered part of retail electric revenues.



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

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

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

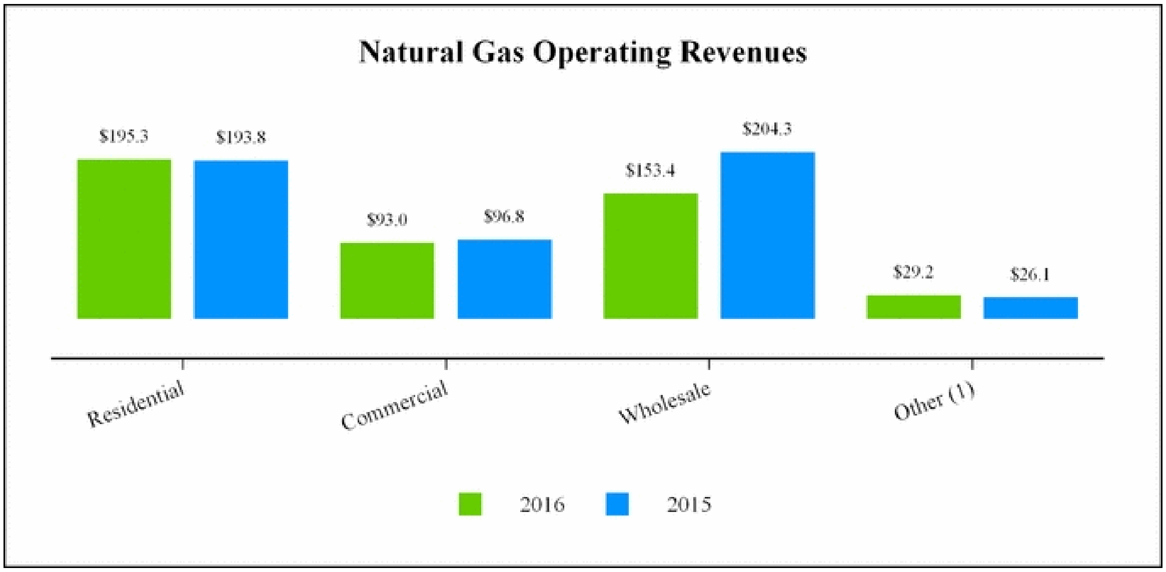
(2) The provision for earnings sharing in Idaho in 2016 resulted from a reduction in the 2015 provision for earnings sharing (which increased 2016 revenues). Beginning in 2016 there is no longer an earnings sharing mechanism in Idaho.

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

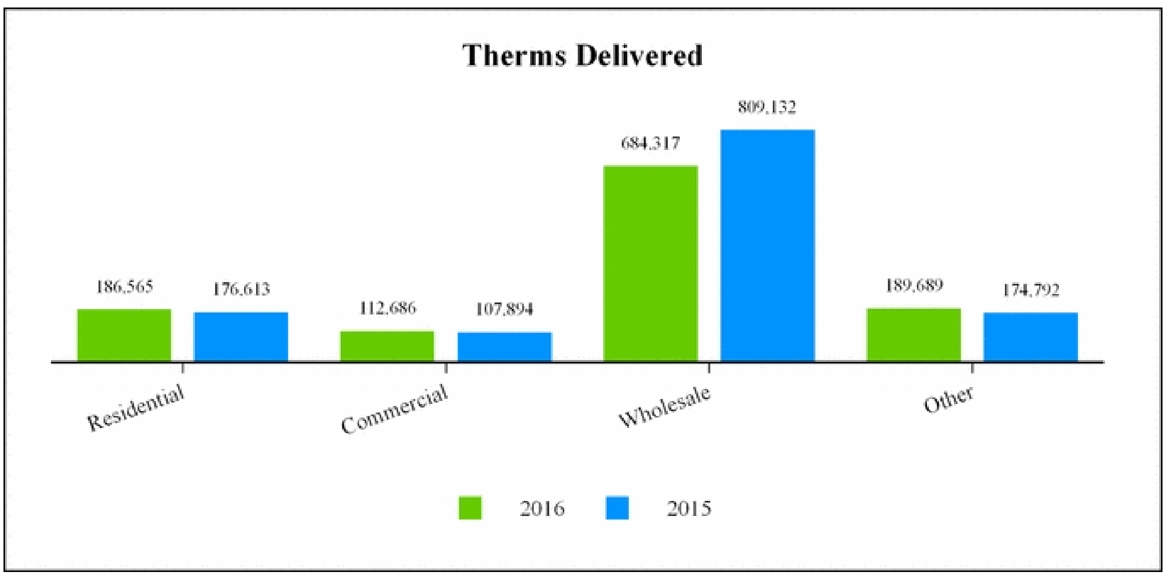
Total electric revenues decreased $0.9 million for 2016 as compared to 2015, affected by the following:

- a $3.0 million decrease in retail electric revenues due to a decrease in total MWhs sold (decreased revenues $9.5 million), partially offset by an increase in revenue per MWh (increased revenues $6.5 million).
  - The increase in revenue per MWh was primarily due to a general rate increase in Idaho and the expiration of the ERM rebate to customers in Washington, partially offset by a general rate decrease in Washington.
  - The decrease in total retail MWhs sold was the result of weather that was cooler in the first quarter (higher electric heating loads), warmer in April and May (lower electric heating loads), cooler June through August (lower electric cooling loads) and cooler in the fourth quarter (higher electric heating loads) as compared to the prior year (which overall decreased electric loads). Compared to 2015, residential electric use per customer decreased 1 percent and commercial use per customer decreased 1 percent. Heating degree days in Spokane were 11 percent below normal and 3 percent above 2015. The impact from increased heating loads was offset by decreased cooling loads in the summer. 2016 cooling degree days were 29 percent above normal (mostly in June). However, cooling degree days were 41 percent below the prior year. The overall decrease in use per customer was partially offset by growth in the number of customers.
  - There has been a decline in residential use per customer during the last three years and is primarily due to weather fluctuations but also due in part to energy efficiency measures adopted by customers. See "Item 1. Business – Avista Utilities Operating Statistics" for the three-year summary of residential use per customer.
- a $15.2 million decrease in wholesale electric revenues due to a decrease in sales volumes (decreased revenues $5.5 million) and a decrease in sales prices (decreased revenues $9.7 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $4.6 million decrease in sales of fuel due to a decrease in sales of natural gas fuel as part of thermal generation resource optimization activities. For 2016, $44.0 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For 2015, $50.0 million of these sales were made to our natural gas operations.
- a $12.6 million increase in electric revenue due to decoupling, which reflected the implementation of a decoupling mechanism in Idaho effective January 1, 2016 and lower retail revenues in 2016 as compared to 2015.
- a $6.6 million decrease in the electric provision for earnings sharing (which increases revenues) due to a $2.5 million reduction in the 2015 provision for earnings sharing in Washington and a $0.7 million reduction in the 2015 provision for earnings sharing in Idaho recorded in 2016. For 2016 electric operations, we recorded a $2.3 million provision for earnings sharing.

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



(1) Other natural gas revenues in the graph above includes interruptible and industrial revenues, which are considered part of retail natural gas revenues.



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

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

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

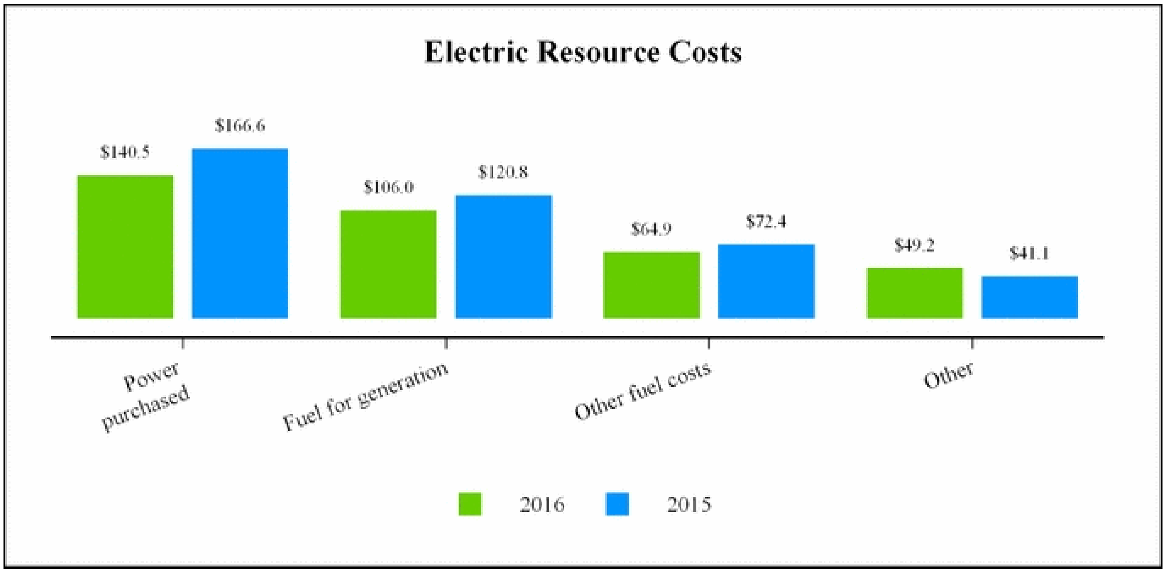
Total natural gas revenues decreased $50.1 million for 2016 as compared to 2015 due to the following:

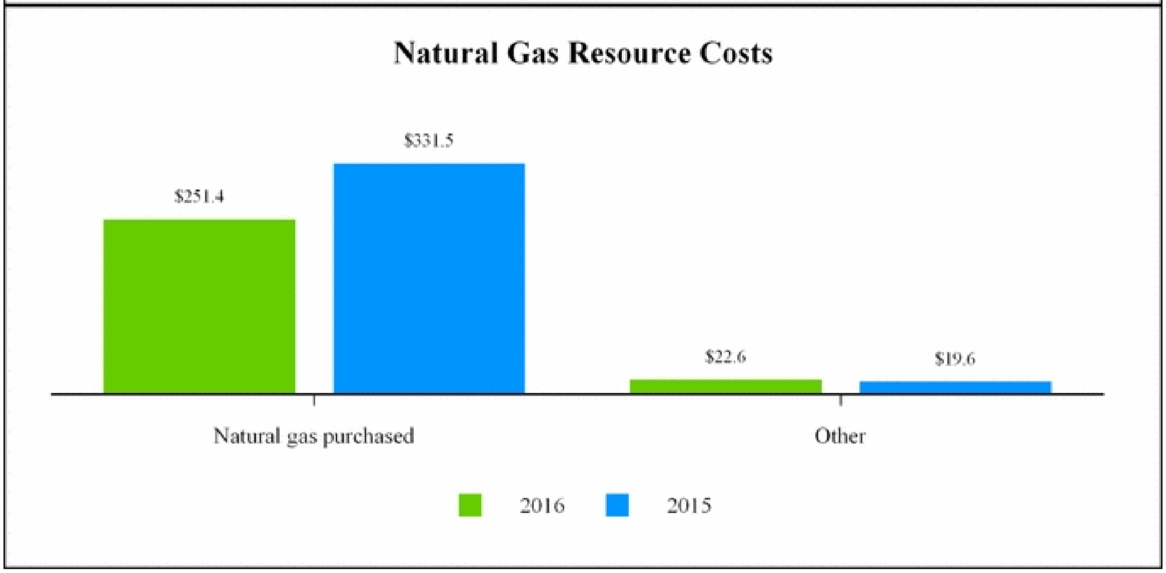
- a $3.4 million decrease in retail natural gas revenues due to lower retail rates (decreased revenues $18.4 million), partially offset by an increase in volumes (increased revenues $15.0 million).
  - Lower retail rates were due to PGAs, which passed through lower costs of natural gas, partially offset by general rate increases.
  - We sold more retail natural gas in 2016 as compared to 2015 primarily due to cooler weather in the first and fourth quarters, as well as customer growth. Compared to 2015, residential use per customer increased 5 percent and commercial use per customer increased 3 percent. Heating degree days in Spokane were 11 percent below historical average for 2016, and 3 percent above 2015. Heating degree days in Medford were 12 percent below historical average for 2016, and 3 percent above 2015.
- a $50.8 million decrease in wholesale natural gas revenues due to a decrease in prices (decreased revenues $22.8 million) and a decrease in volumes (decreased revenues $28.0 million). In 2016, $51.2 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In 2015, $57.0 million of these sales were made to our electric generation operations. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.
- a $6.3 million increase for natural gas decoupling revenues due primarily to the implementation of decoupling mechanisms in Idaho and Oregon, as well as an increase in the decoupling surcharge in Washington.
- a $2.8 million increase in the provision for earnings sharing (which decreases revenues) representing the 2016 provision for Washington natural gas operations.

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

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

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





Total resource costs in the graphs above include intracompany resource costs of $95.2 million and $107.0 million for 2016 and 2015, respectively.

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

- a $26.1 million decrease in power purchased due to a decrease in the volume of power purchases (decreased costs $9.3 million) and a decrease in wholesale prices (decreased costs $16.8 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $14.8 million decrease in fuel for generation primarily due to a decrease in thermal generation (due in part to increased hydroelectric generation) and a decrease in natural gas fuel prices.
- a $7.5 million decrease in other fuel costs.
- a $3.0 million decrease from amortizations and deferrals of power costs.
- a $5.6 million increase in other electric resource costs primarily due to a benefit that was recorded during 2015 related

to a capacity contract of Spokane Energy. This benefit was mostly deferred for probable future benefit to customers through the ERM and PCA.

- a $5.4 million increase in other regulatory amortizations.

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

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

2015 compared to 2014

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

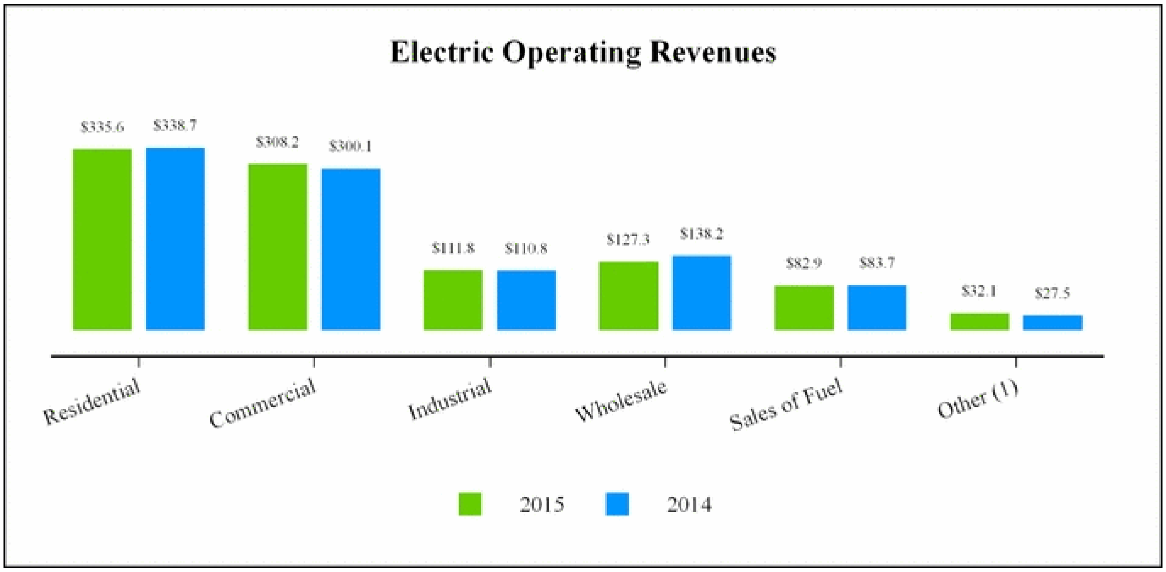
	Electric		Natural Gas		Intracompany		Total	
	2015	2014	2015	2014	2015	2014	2015	2014
Operating revenues	$ 997,873	$ 998,988	$ 521,010	$ 556,664	$ (107,020)	$ (142,153)	$ 1,411,863	$ 1,413,499
Resource costs	400,910	418,541	351,101	395,956	(107,020)	(142,153)	644,991	672,344
Gross margin	$ 596,963	$ 580,447	$ 169,909	$ 160,708	$ —	$ —	$ 766,872	$ 741,155

The gross margin on electric sales increased $16.5 million and the gross margin on natural gas sales increased $9.2 million. The increase in electric gross margin was primarily due to a general rate increase in Washington, lower net power supply costs and a $1.9 million decrease in the provision for earnings sharing (which is an offset to revenue). We experienced weather that was significantly warmer than normal and warmer than the prior year, which decreased heating loads in the first quarter and increased cooling loads in the second quarter. Loads in the third quarter were slightly higher than the prior year. Loads for the fourth quarter were lower than the prior year, particularly for residential and industrial customers. For 2015, the decoupling mechanism in Washington had a positive effect on each of electric revenues and gross margin as did the decrease in the overall provision for earnings sharing (see the details by jurisdiction in the table below). For 2015, we recognized a pre-tax benefit of $6.3 million under the ERM in Washington compared to a benefit of $5.4 million for 2014. This change represents a decrease in net power supply costs primarily due to lower natural gas fuel and purchased power prices in 2015, partially offset by lower hydroelectric generation (due to warm and dry conditions in the second and third quarters).

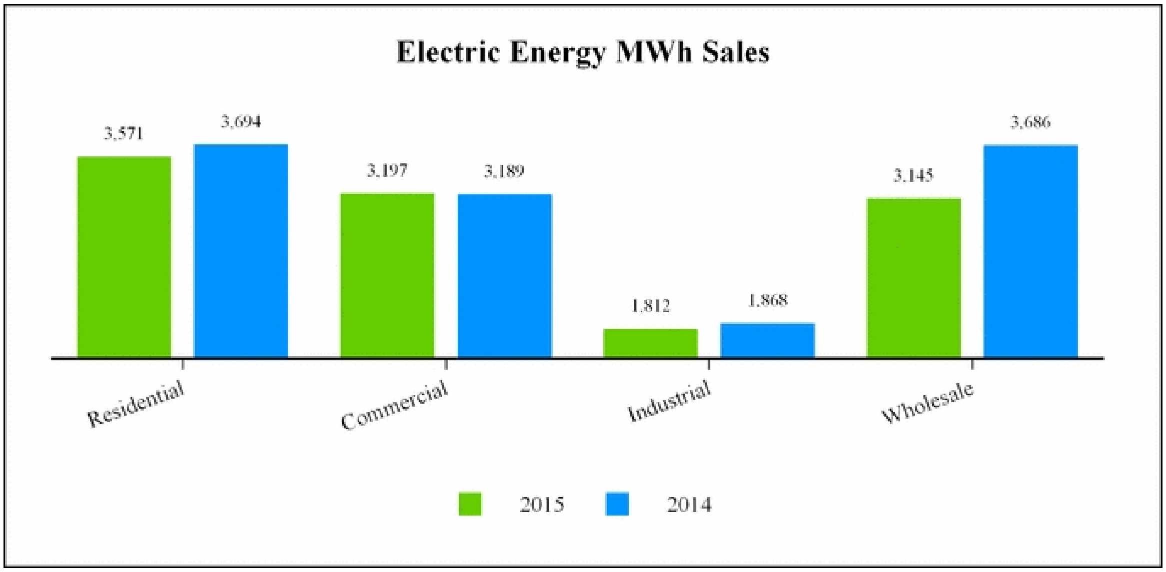
The increase in natural gas gross margin was primarily due to a decrease in natural gas resource costs and a decrease in the provision for earnings sharing, partially offset by a decrease in natural gas revenues. The decrease in natural gas revenues resulted from lower heating loads primarily from significantly warmer weather that was partially offset by general rate increases. The earnings impact of the decrease in heating loads was partially offset by the decoupling mechanism in Washington, which had a positive effect on natural gas revenues and gross margin (see the details by jurisdiction in the table below).

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

The following 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) Other electric revenues in the graph above includes public street and highway lighting, which is considered part of retail electric revenues.



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

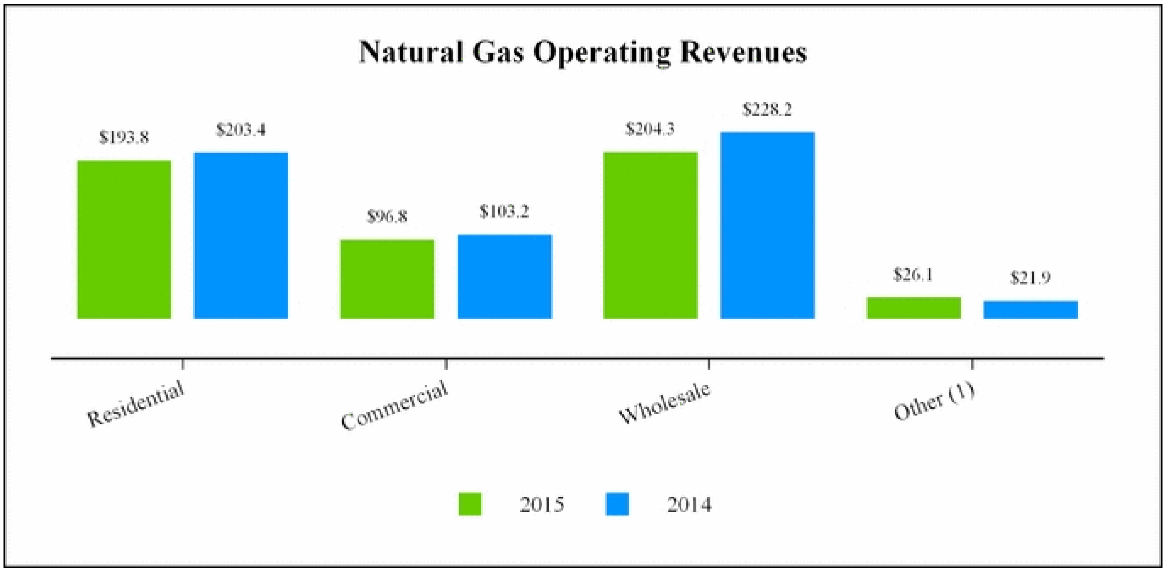
	Electric Operating Revenues	
	2015	2014
Washington		
Decoupling	$ 4,740	n/a
Provision for earnings sharing	(3,423)	n/a
Idaho		
Decoupling	n/a	n/a
Provision for earnings sharing	(2,198)	(7,503)

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

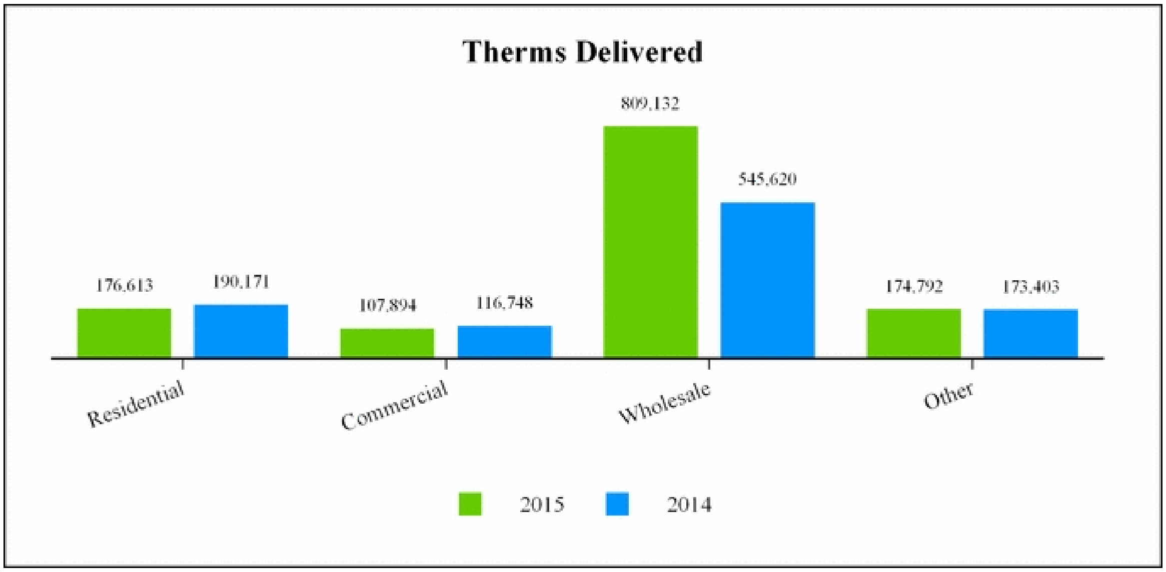
Total electric revenues decreased $1.1 million for 2015 as compared to 2014, affected by the following:

- a $5.7 million increase in retail electric revenues due to an increase in revenue per MWh (increased revenues $21.0 million), partially offset by a decrease in total MWhs sold (decreased revenues $15.3 million). The increase in revenue per MWh was primarily due to a general rate increase in Washington. The decrease in total MWhs sold was primarily the result of weather that was significantly warmer than normal and warmer than the prior year, which decreased the electric heating load in the first quarter. Compared to 2014, residential electric use per customer decreased 5 percent and commercial use per customer decreased 2 percent. Heating degree days in Spokane were 14 percent below normal and 10 percent below 2014. The impact from reduced heating loads was partially offset by increased cooling loads in the summer. Year-to-date cooling degree days were 141 percent above normal and 28 percent above the prior year.
- a $10.9 million decrease in wholesale electric revenues due to a decrease in sales volumes (decreased revenues $21.9 million), partially offset by an increase in sales prices (increased revenues $11.0 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $0.9 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 2015, $50.0 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For 2014, $67.4 million of these sales were made to our natural gas operations.
- a $4.7 million increase in electric revenue due to decoupling, which reflected decreased heating loads in the first and fourth quarters, partially offset by increased cooling loads in the second and third quarters.
- a $1.9 million decrease in the provision for earnings sharing, primarily due to a decrease of $5.3 million for our Idaho electric operations, partially offset by an increase of $3.4 million for our Washington electric operations. In 2014, we recorded a provision for earnings sharing of $7.5 million for Idaho electric customers with $5.6 million representing our estimate for 2014 and $1.9 million representing an adjustment to our 2013 estimate.

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) Other natural gas revenues in the graph above includes interruptible and industrial revenues, which are considered part of retail natural gas revenues.



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

	Natural Gas Operating Revenues	
	2015	2014
Washington		
Decoupling	$ 6,004	n/a
Provision for earnings sharing	—	n/a
Idaho		
Decoupling	—	n/a
Provision for earnings sharing	—	(221)

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

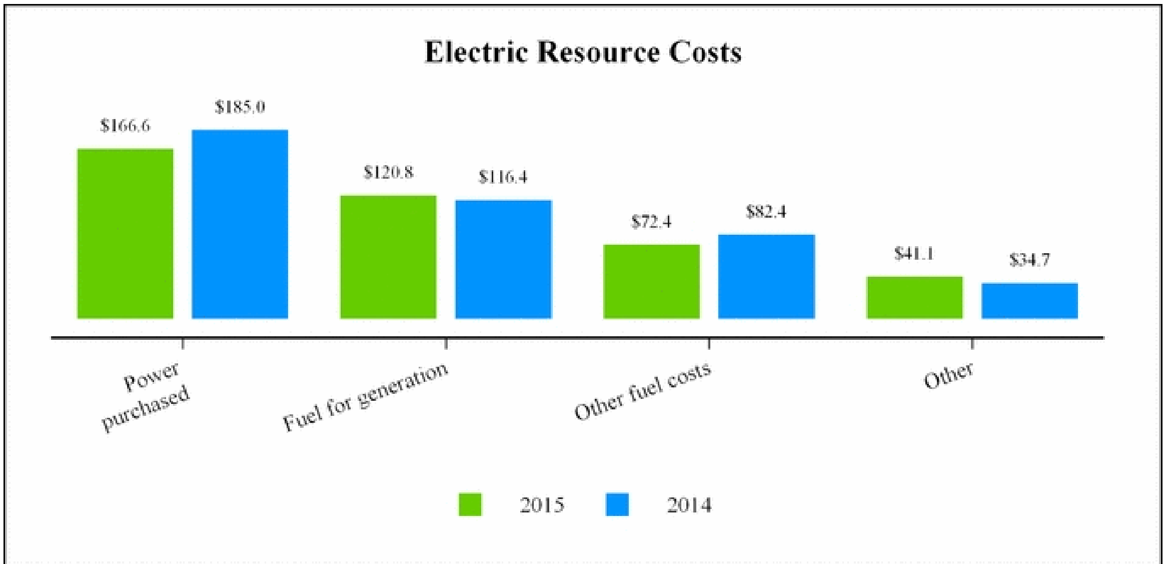
Total natural gas revenues decreased $35.7 million for 2015 as compared to 2014 due to the following:

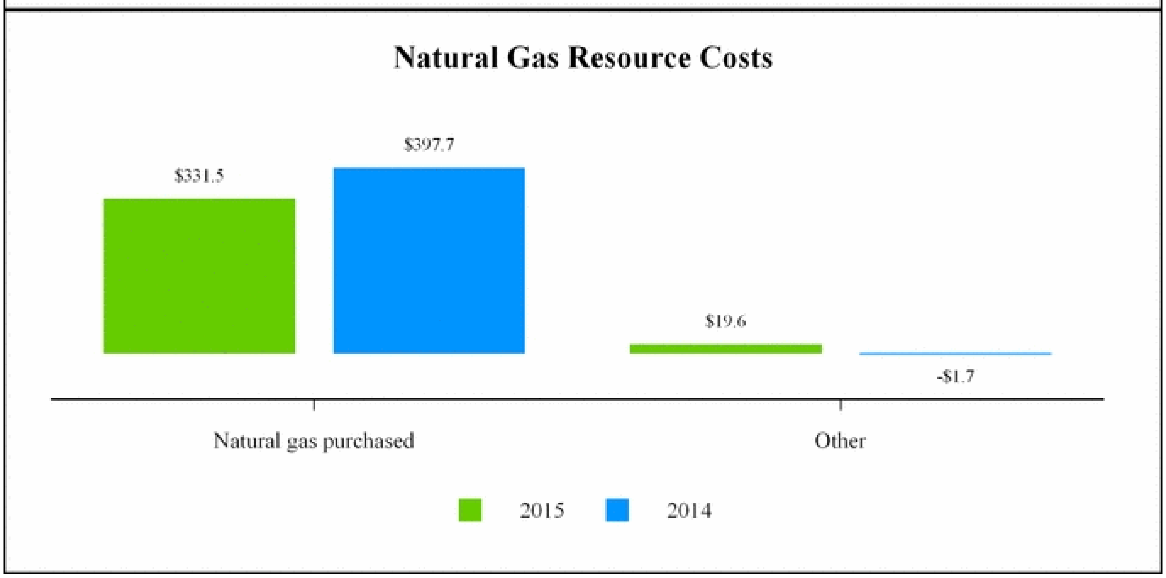
- a $16.4 million decrease in retail natural gas revenues due to a decrease in volumes (decreased revenues $23.6 million), partially offset by higher retail rates (increased revenues $7.2 million). Higher retail rates were due to PGAs implemented in November 2014, which passed through higher costs of natural gas, and general rate cases. This was partially offset by PGA rate decreases implemented in November 2015, which passed through lower costs. We sold less retail natural gas in 2015 as compared to 2014 primarily due to weather that was warmer than normal and warmer than the prior year. Compared to 2014, residential use per customer decreased 9 percent and commercial use per customer decreased 9 percent. Heating degree days in Spokane were 14 percent below historical average for 2015, and 10 percent below 2014. Heating degree days in Medford were 15 percent below historical average for 2015, and 4 percent above 2014.
- a $23.9 million decrease in wholesale natural gas revenues due to a decrease in prices (decreased revenues $90.4 million), partially offset by an increase in volumes (increased revenues $66.5 million). In 2015, $57.0 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In 2014, $74.7 million of these sales were made to our electric generation operations. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.
- a $6.0 million increase for natural gas decoupling revenues due primarily to significantly warmer than normal weather and the impact on heating loads.

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	
	2015	2014	2015	2014
Residential	327,057	324,188	296,005	291,928
Commercial	41,296	40,988	34,229	34,047
Interruptible	—	—	35	37
Industrial	1,353	1,385	261	264
Public street and highway lighting	529	531	—	—
Total retail customers	370,235	367,092	330,530	326,276

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





Total resource costs in the graphs above include intracompany resource costs of $107.0 million and $142.2 million for 2015 and 2014, respectively.

Total electric resource costs decreased $17.6 million for 2015 as compared to 2014 due to the following:

- an $18.3 million decrease in power purchased due to a decrease in the volume of power purchases (decreased costs $23.6 million), partially offset by an increase in wholesale prices (increased costs $5.3 million). The fluctuation in volumes and prices was primarily the result of our overall optimization activities.
- a $4.4 million increase in fuel for generation primarily due to an increase in thermal generation (due in part to decreased hydroelectric generation), partially offset by a decrease in natural gas fuel prices.
- a $10.0 million decrease in other fuel costs.
- a $14.2 million increase from amortizations and deferrals of power costs.
- a $7.7 million decrease in other electric resource costs primarily due to the benefit from a capacity contract of Spokane

Energy, which was mostly deferred for probable future benefit to customers through the ERM and PCA.

Total natural gas resource costs decreased $44.9 million for 2015 as compared to 2014 due to the following:

- a $66.1 million decrease in natural gas purchased due to a decrease in the price of natural gas (decreased costs $138.3 million), partially offset by an increase in total therms purchased (increased costs $72.2 million). Total therms purchased increased due to an increase in wholesale sales, partially offset by a decrease in retail sales.
- a $21.8 million increase from amortizations and deferrals of natural gas costs. This reflects lower natural gas prices and the deferral of lower costs for future rebate to customers.

Results of Operations - Alaska Electric Light and Power Company

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

2016 compared to 2015

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

The increase in gross margin was primarily related to a decrease in costs associated with the Snettisham hydroelectric project (due to a refinancing transaction during the second half of 2015 which lowered interest costs under the take-or-pay power purchase agreement), as well as an interim rate increase effective in November 2016. These were partially offset by a slight decrease in sales volumes to commercial and government customers and an increase in other resource costs.

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

2015 compared to 2014

Net income for AEL&P was $6.6 million for the year ended December 31, 2015, compared to $3.2 million for the second half of 2014. Since AEL&P was acquired on July 1, 2014, the results for 2015 are not comparable to 2014 as 2014 only includes results for the second half of the year.

Results of Operations - Ecova - Discontinued Operations

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

2016 compared to 2015 and 2014

There was zero net income or loss for 2016. Ecova's net income was $5.1 million for 2015, compared to net income of $72.4 million for 2014. The net income for 2015 was primarily related to a tax benefit during 2015 that resulted from the reversal of a valuation allowance against net operating losses at Ecova because the net operating losses were deemed realizable under the current tax code. Additionally, there were some minor true-ups to the gain recognized on the sale due to the settlement of the working capital and indemnification escrow accounts during 2015. The results for 2014 included $69.7 million of the net gain recognized on the sale of Ecova.

Results of Operations - Other Businesses

2016 compared to 2015

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

2015 compared to 2014

The net loss from these operations was $1.9 million for 2015 compared to net income of $3.2 million for 2014. The decrease in net income compared to 2014 was primarily due to the settlement of the California power markets litigation in 2014, where Avista Energy received settlement proceeds from a litigation with various California parties related to the prices paid for power in the California spot markets during the years 2000 and 2001. This settlement resulted in an increase in pre-tax earnings of approximately $15.0 million. This was partially offset by a pre-tax contribution of $6.4 million of the proceeds to the Avista Foundation.

In addition, the decrease in earnings for 2015 related to an increase in net losses on investments, partially offset by an increase in net income at METALfx and a slight decrease in corporate costs, including costs associated with exploring strategic opportunities.

Accounting Standards to be Adopted in 2017

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 2017. However, we will be adopting ASU No. 2014-09 "Revenue from Contracts with Customers (Topic 606)" in 2018 upon its effective date. This is a significant new accounting standard that requires an extensive amount of time and effort to implement. We currently expect to use a modified retrospective method of adoption, which would require a cumulative adjustment to opening retained earnings, as opposed to a full retrospective application. The Company is not far enough along in the adoption process to determine the amount, if any, of cumulative adjustment necessary.

Since the vast majority of Avista Corp.'s revenue is from rate regulated sales of electricity and natural gas to retail customers and revenue is recognized as energy is delivered to these customers, we do not expect a significant change in operating revenues or net income due to adopting this standard.

The Company is in the process of reviewing and analyzing certain contracts with customers (most of which are related to wholesale sales of power and natural gas) but has not yet identified any significant differences in revenue recognition between current GAAP and the new revenue recognition standard.

There are unresolved issues associated with implementing this standard, including the presentation of CIACs, the presentation of utility taxes on a gross basis and determining collectibility of sales to low income customers. We are monitoring utility industry implementation guidance as it relates to unresolved issues to determine if there will be an industry consensus regarding accounting and presentation of these items.

For information on accounting standards adopted in 2016 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 regulatory revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the current period Consolidated Statement of Income. Any amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. This could ultimately result in more decoupling revenue being collected from customers over the life of the decoupling program than what is deferred and recognized in the current period financial statements. We make estimates regarding the amount of revenue that will be collected within 24 months of deferral. We also make the assumption that there are regulatory precedents for many of our regulatory items and that we will be allowed recovery of these costs via retail rates in future periods. If we were no longer allowed to apply regulatory accounting or no longer allowed recovery of these costs, we could be required to recognize significant write-offs of regulatory assets and liabilities in the Consolidated Statements of Income. See "Notes 1 and 20 of the Notes to Consolidated Financial Statements" for further discussion of our regulatory accounting policy.

- ***Utility energy commodity derivative asset and liability accounting***, where we estimate the fair value of outstanding commodity derivatives and we offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. This accounting treatment is supported by accounting orders issued by the UTC and IPUC. If we were no longer allowed to apply regulatory accounting or no longer allowed recovery of these costs, we could be required to recognize significant changes in fair value of these energy commodity derivatives on a regular basis in the Consolidated Statements of Income, which could lead to significant fluctuations in net income. See "Notes 1 and 6 of the Notes to Consolidated Financial Statements" for further discussion of our energy derivative accounting policy.
- ***Interest rate 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. If we no longer applied regulatory accounting or were no longer allowed recovery of these costs, we could be required to recognize significant changes in fair value of these interest rate swap derivatives on a regular basis in the Consolidated Statements of Income, which could lead to significant fluctuations in net income.
- ***Pension Plans and Other Postretirement Benefit Plans***, discussed in further detail below.
- ***Contingencies,*** related to unresolved regulatory, legal and tax issues for which there is inherent uncertainty for the ultimate outcome of the respective matter. We accrue a loss contingency if it is probable that an asset is impaired or a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. We also disclose losses that do not meet these conditions for accrual, if there is a reasonable possibility that a potential loss may be incurred. For all material contingencies, we have made a judgment as to the probability of a loss occurring and as to whether or not the amount of the loss can be reasonably estimated. If the loss recognition criteria are met, liabilities are accrued or assets are reduced. However, no assurance can be given to the ultimate outcome of any particular contingency. See "Notes 1 and 19 of the Notes to Consolidated Financial Statements" for further discussion of our commitments and contingencies.

Pension Plans and Other Postretirement Benefit Plans - Avista Utilities

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

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

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

Our pension plan assets are invested in debt securities and mutual funds, trusts and partnerships that hold marketable debt and equity securities, real estate and absolute return funds. In seeking to obtain the desired return to fund the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes and also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range. During 2016, we revised the target investment allocation percentages. See "Note 10 of the Notes to Consolidated Financial Statements" for the target investment allocation percentages and further discussion of the revision.

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

Pension costs (including the SERP) were $26.8 million for 2016, $27.1 million for 2015 and $14.6 million for 2014. Of our pension costs, approximately 60 percent are expensed and 40 percent are capitalized consistent with labor charges. The costs related to the SERP are expensed. Our costs for the pension plan are determined in part by actuarial formulas that are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs are affected by among other things:

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

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

We revise the key assumption of the discount rate each year. In selecting a discount rate, we consider yield rates at the end of the year for highly rated corporate bond portfolios with cash flows from interest and maturities similar to that of the expected payout of pension benefits. In 2016, the pension plan discount rate (exclusive of the SERP) was 4.26 percent compared to 4.58 percent in 2015 and 4.21 percent in 2014. These changes in the discount rate increased the projected benefit obligation (exclusive of the SERP) by approximately $27.7 million in 2016 and decreased the obligation by $31.0 million in 2015.

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. We used an expected long-term rate of return of 5.40 percent in 2016, 5.30 percent in 2015 and 6.60 percent in 2014. This change decreased pension costs by approximately $0.5 million in 2016. The actual return on plan assets, net of fees, was a gain of $43.2 million (or 8.1 percent) for 2016, a loss of $4.3 million (or 0.8 percent) for 2015 and a gain of $56.0 million (or 11.6 percent) for 2014.

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

Actuarial Assumption	Change in Assumption	Effect on Projected Benefit Obligation	Effect on Pension Cost
Expected long-term return on plan assets	(0.5)%	$ — *	$ 2,551
Expected long-term return on plan assets	0.5 %	— *	(2,551)
Discount rate	(0.5)%	47,738	3,842
Discount rate	0.5 %	(42,462)	(3,441)

* 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, 2016 by $8.6 million and the service and interest cost by $1.0 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, 2016 by $6.7 million and the service and interest cost by $0.7 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. In December 2016, the UTC issued an order related to our Washington electric and natural gas general rate cases that were originally filed with the UTC in February 2016. The UTC order denied the Company's proposed electric and natural gas rate increase requests totaling $43.0 million. If this order is not changed as a result of reconsideration, rehearing or judicial review, we expect it will have a negative impact on our net income in 2017. See further details in the section "Regulatory Matters."

For Avista Utilities, when power and natural gas costs exceed the levels currently recovered from retail customers, net cash flows are negatively affected. Factors that could cause purchased power and natural gas costs to exceed the levels currently recovered from our customers include, but are not limited to, higher prices in wholesale markets when we buy energy or an increased need to purchase power in the wholesale markets, 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.

Avista Utilities has regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, if prices rise above the level currently allowed in retail rates in periods when we are buying energy, deferral balances would increase, negatively affecting our cash flow and liquidity until such time as these costs, with interest, are recovered from customers.

In addition to the above, Avista Utilities enters into derivative instruments to hedge our exposure to certain risks, including fluctuations in commodity market prices, foreign exchange rates and interest rates (for purposes of issuing long-term debt in the future). These derivative instruments often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement, in the event of a downgrade in the Company's credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. See "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, 2016, we had $245.6 million of available liquidity under the Avista Corp. committed line of credit and $25.0 million under the AEL&P committed line of credit. With our $400.0 million credit facility that expires in April 2021 and AEL&P's $25.0 million credit facility that expires in November 2019, we believe that we have adequate liquidity to meet our needs for the next 12 months.

Review of Consolidated Cash Flow Statement

Overall

During 2016, cash flows from operating activities were $358.3 million, proceeds from the issuance of long-term debt were $245.0 million (including a $70.0 million bridge loan that was repaid in December 2016), net proceeds from our committed line of credit were $15.0 million and we received $67.0 million from the issuance of common stock. Cash requirements included utility capital expenditures of $406.6 million, the payment of long-term debt of $163.2 million (including the $70.0 million bridge loan), dividends of $87.2 million and cash paid for the settlement of interest rate swap derivatives of $54.0 million.

2016 compared to 2015

Consolidated Operating Activities

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

The cash flow decreases were partially offset by higher net income after non-cash adjustments of $446.4 million in 2016, compared to $392.3 million in 2015.

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

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

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

The provision for deferred income taxes was $124.5 million for 2016, compared to $51.8 million for 2015. The change in the provision for deferred income taxes was primarily related to deferred taxes on property, plant and equipment, investment tax credits associated with our capital projects, deferred taxes on the decoupling regulatory assets and deferred taxes on interest rate swap derivatives.

Consolidated Investing Activities

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

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

Consolidated Financing Activities

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

- borrowing of $70.0 million pursuant to a term loan agreement in August, which was used to repay a portion of the $90.0 million in first mortgage bonds that matured in August 2016,

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

See below for a list of significant financing transactions occurring in 2015.

2015 compared to 2014

Consolidated Operating Activities

Net cash provided by operating activities was $375.6 million for 2015 compared to $267.3 million for 2014. The increase in cash provided by operating activities was due to higher net income after non-cash adjustments of $392.3 million in 2015, compared to $348.2 million in 2014. The gross gain on the sale of Ecova of $0.8 million for 2015 is deducted in reconciling net income to net cash provided by operating activities. The cash proceeds from the sale (which includes the gross gain) is included in investing activities. This is compared to the gross gain recognized in 2014 of $160.6 million.

Net cash used by certain current assets and liabilities was $4.1 million for 2015, compared to net cash used of $50.0 million for 2014. The net cash used during 2015 primarily reflects cash outflows from changes in accounts payable, collateral posted for derivative instruments and accounts receivable. This was partially offset by inflows from changes in natural gas stored and income taxes receivable.

The provision for deferred income taxes was $51.8 million for 2015 compared to $144.3 million for 2014. The decrease in 2015 was primarily due to the combination of implementation by the Company of updated federal tax tangible property regulations and increased deductions related to bonus depreciation in 2014.

Contributions to our defined benefit pension plan were $12.0 million for 2015 compared to $32.0 million in 2014.

Net cash received for income taxes was $10.0 million for 2015 compared to net cash paid of $45.4 million for 2014.

Consolidated Investing Activities

Net cash used in investing activities was $387.8 million for 2015, an increase compared to $103.7 million for 2014. During 2015, we received cash proceeds (related to the settlement of the escrow accounts) of $13.9 million for the sale of Ecova. We received the majority of the proceeds ($229.9 million) from the sale of Ecova during 2014. The proceeds received in 2014 were used to pay off the balance of Ecova's long-term borrowings and make payments to option holders and noncontrolling interests (included in financing activities). We also used a portion of these proceeds to pay our $74.8 million tax liability associated with the gain on sale and to fund common stock repurchases. Utility property capital expenditures increased by $67.9 million for 2015 as compared to 2014. During 2014, we received $15.0 million in cash (net of cash paid) related to the acquisition of AERC.

Consolidated Financing Activities

Net cash provided by financing activities was $0.5 million for 2015 compared to net cash used of $224.0 million for 2014. In 2015 we had the following significant transactions:

- issuance and sale of $100.0 million of Avista Corp. first mortgage bonds in December 2015,
- payment of $2.9 million for the redemption and maturity of long-term debt,
- cash dividends paid increased to $82.4 million (or $1.32 per share) for 2015 from $78.3 million (or $1.27 per share) for 2014,
- issuance of $1.6 million of common stock (net of issuance costs), and
- repurchase of $2.9 million of our common stock.

In 2014, we had the following significant transactions:

- issuance of $150.0 million of long-term debt ($60.0 million of Avista Corp. first mortgage bonds, $75.0 million of AEL&P first mortgage bonds and a $15.0 million AERC unsecured note representing a term loan),
- a decrease of $66.0 million in short-term borrowings on Avista Corp.'s committed line of credit,
- a decrease of $46.0 million on Ecova's committed line of credit with $6.0 million in payments throughout the year and $40.0 million related to the close of the Ecova sale,
- payment of $40.0 million for the redemption and maturity of long-term debt (primarily related to AEL&P paying off its existing debt),
- cash payments of $54.2 million to noncontrolling interests and $20.9 million to stock option holders and redeemable noncontrolling interests of Ecova related to the Ecova sale in 2014,
- issuance of $4.1 million of common stock (net of issuance costs) excluding issuances related to the acquisition of AERC. We issued $150.1 million of common stock to AERC shareholders, and this is reflected as a non-cash financing activity,
- repurchase of $79.9 million of our common stock during 2014 using the proceeds from our sale of Ecova, and
- a $16.2 million increase in cash related to the fluctuation in the balance of customer fund obligations at Ecova.

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, and excluding noncontrolling interests, consisted of the following as of December 31, 2016 and 2015 (dollars in thousands):

	December 31, 2016		December 31, 2015	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and capital leases	$ 3,287	0.1%	$ 93,167	2.9%
Short-term borrowings	120,000	3.4%	105,000	3.2%
Long-term debt to affiliated trusts	51,547	1.5%	51,547	1.6%
Long-term debt and capital leases	1,678,717	47.9%	1,480,111	45.4%
Total debt	1,853,551	52.9%	1,729,825	53.1%
Total Avista Corporation shareholders' equity	1,648,727	47.1%	1,528,626	46.9%
Total	$ 3,502,278	100.0%	$ 3,258,451	100.0%

Our shareholders' equity increased $120.1 million during 2016 primarily due to net income, the issuance of common stock and stock compensation net of minimum tax withholdings, partially offset by dividends.

We need to finance capital expenditures and acquire additional funds for operations from time to time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduce the amount of cash flow available to fund capital expenditures, purchased power, fuel and natural gas costs, dividends and other requirements.

Committed Lines of Credit

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. We exercised a two-year option in May 2016 to extend the maturity of the credit facility agreement to April 2021. As of December 31, 2016, we had $245.6 million of available liquidity under this line of credit.

The Avista Corp. credit facility contains customary covenants and default provisions, including a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time. As of December 31, 2016, we were in compliance with this covenant with a ratio of 52.9 percent.

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

The AEL&P credit facility contains customary covenants and default provisions including a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," (including the impact of the Snettisham obligation) to be greater than 67.5 percent at any time. As of December 31, 2016, AEL&P was in compliance with this covenant with a ratio of 55.6 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):

	2016	2015	2014
Balance outstanding at end of year	$ 120,000	$ 105,000	$ 105,000
Letters of credit outstanding at end of year	$ 34,353	$ 44,595	$ 32,579
Maximum balance outstanding during the year	$ 280,000	$ 180,000	$ 171,000
Average balance outstanding during the year	$ 171,090	$ 95,573	$ 62,088
Average interest rate during the year	1.26%	0.98%	1.01%
Average interest rate at end of year	1.50%	1.18%	0.93%

As of December 31, 2016, Avista Corp. and its subsidiaries were in compliance with all of the covenants of their financing agreements, and none of Avista Corp.'s subsidiaries constituted a “significant subsidiary” as defined in Avista Corp.'s committed line of credit.

Long-Term Debt Borrowings

In August 2016, we entered into a term loan agreement with a commercial bank in the amount of $70.0 million with a maturity date of December 30, 2016. We borrowed the entire $70.0 million available under this agreement, which was used to repay a portion of the $90.0 million of first mortgage bonds that matured in August 2016. We repaid this term loan in its entirety in December using the proceeds from first mortgage bonds that were issued in December 2016.

In December 2016, we issued and sold $175.0 million of 3.54 percent first mortgage bonds due in 2051 pursuant to a bond purchase agreement with institutional investors in the private placement market. In connection with the pricing of the first mortgage bonds in August 2016, the Company cash-settled seven interest rate swap derivatives (notional aggregate amount of $125.0 million) and paid a total of $54.0 million, which will be amortized as a component of interest expense over the life of the debt. The effective interest rate of the first mortgage bonds is 5.6 percent, including the effects of the settled interest rate swap derivatives and estimated issuance costs.

The total net proceeds from the sale of the new bonds was used to repay the $70.0 million term loan and to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit.

Equity Transactions

Stock Repurchase Programs

During 2014 and 2015, Avista Corp.'s Board of Directors approved programs to repurchase shares of our outstanding common stock. The number of shares repurchased and the total cost of repurchases are disclosed in the Consolidated Statements of Equity and Redeemable Noncontrolling Interests. The average repurchase price was $31.57 in 2014 and $32.66 in 2015. All repurchased shares reverted to the status of authorized but unissued shares.

We did not repurchase any of our outstanding common stock during 2016.

Equity Issuances

In March 2016, we entered into four separate sales agency agreements under which Avista Corp.’s sales agents may offer and sell up to 3.8 million new shares of Avista Corp.'s common stock, no par value, from time to time. The sales agency agreements expire on February 29, 2020. In 2016, 1.6 million shares were issued under these agreements resulting in total net proceeds of $65.3 million, leaving 2.2 million shares remaining to be issued.

In 2016, we also issued $1.7 million (net of issuance costs) of common stock under the employee plans.

2017 Liquidity Expectations

In the second half of 2017, we expect to issue approximately $110.0 million of long-term debt and up to $70.0 million of common stock in order to fund planned capital expenditures and maintain an appropriate capital structure.

After considering the expected issuances of long-term debt and common stock during 2017, 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, 2016, we could issue $1.5 billion of additional preferred stock at an assumed dividend rate of 6.3 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, 2016, 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 $20.8 million at AEL&P. We believe that we have adequate capacity to issue first mortgage bonds to meet our financing needs over the next several years.

Capital Expenditures

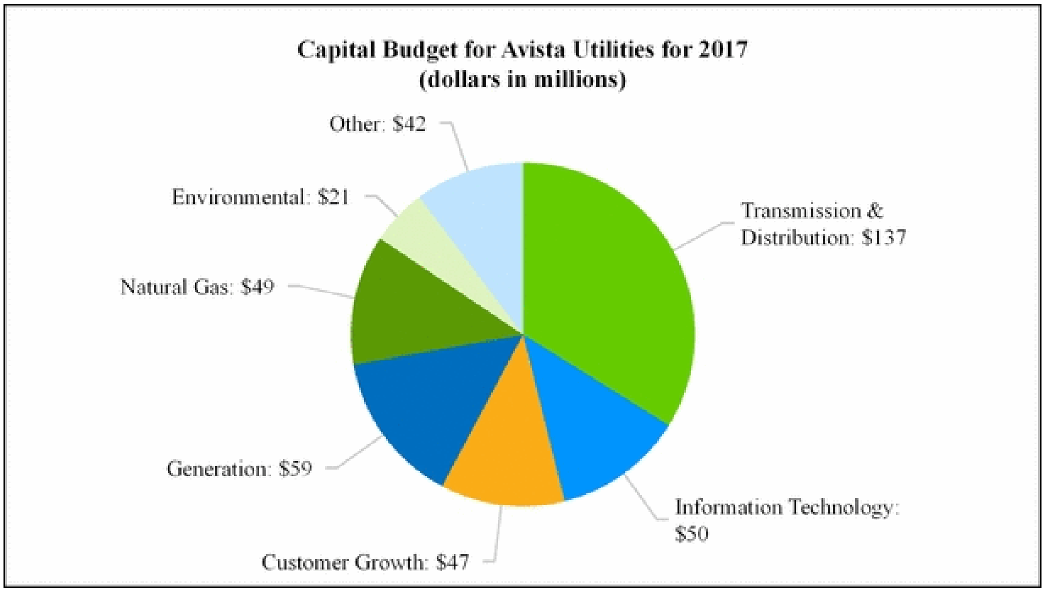
We are making capital investments in generation, transmission and distribution systems to preserve and enhance service reliability for our customers and replace aging infrastructure. The following table summarizes our actual and expected capital expenditures as of and for the year ended December 31, 2016 (in thousands):

	Avista Utilities	AEL&P
2016 Actual capital expenditures		
Capital expenditures (per the Consolidated Statement of Cash Flows) (1)	390,690	15,954
Expected total annual capital expenditures (by year)		
2017	405,000	6,900
2018	405,000	6,700
2019	405,000	12,900

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

Most of the capital expenditures at Avista Utilities are for upgrading our existing facilities and technology, and not for construction of new facilities.

The following graph shows the Avista Utilities' capital budget for 2017:



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

Off-Balance Sheet Arrangements

As of December 31, 2016, we had $34.4 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $44.6 million as of December 31, 2015.

Pension Plan

We contributed $12.0 million to the pension plan in 2016. We expect to contribute a total of $110.0 million to the pension plan in the period 2017 through 2021, 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 21, 2017:

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

(1) Standard & Poor’s lowest “investment grade” credit rating is BBB-.
(2) Moody’s lowest “investment grade” credit rating is Baa3.

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

Dividends

On February 3, 2017, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.3575 per share on the Company's common stock. This was an increase of $0.015 per share, or 4.4 percent from the previous quarterly dividend of $0.3425 per share.

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

Contractual Obligations

The following table provides a summary of our future contractual obligations as of December 31, 2016 (dollars in millions):

	2017	2018	2019	2020	2021	Thereafter
Avista Utilities:						
Long-term debt maturities	$ —	$ 273	$ 90	$ 52	$ —	$ 1,124
Long-term debt to affiliated trusts	—	—	—	—	—	52
Interest payments on long-term debt (1)	80	70	63	58	56	836
Short-term borrowings	120	—	—	—	—	—
Energy purchase contracts (2)	298	252	228	151	126	1,125
Operating lease obligations (3)	1	1	—	—	—	2
Other obligations (4)	34	29	33	32	27	189
Information technology contracts (5)	2	1	—	—	—	—
Pension plan funding (6)	22	22	22	22	22	—
Unsettled interest rate swap derivatives (7)	12	54	(3)	(2)	—	(1)
AERC (consolidated) total contractual commitments (8)	16	16	31	15	15	295
Avista Capital (consolidated) total contractual commitments (9)	8	8	7	4	1	4
Total contractual obligations	$ 593	$ 726	$ 471	$ 332	$ 247	$ 3,626

(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, 2016.

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

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

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

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

(6) Represents our estimated cash contributions to pension plans and other postretirement benefit plans through 2021. We cannot reasonably estimate pension plan contributions beyond 2021 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, 2016. 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 $34.9 million and letters of credit of $3.6 million that are already posted with counterparties against the outstanding interest rate swap derivatives.

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

(9) Primarily relates to operating lease commitments and a commitment to fund a limited liability company in exchange for equity ownership, made by a subsidiary of Avista Capital.

The above contractual obligations do not include income tax payments. Also, asset retirement obligations are not included above and payments associated with these have historically been less than $1 million per year. There are approximately $15.5 million remaining asset retirement obligations as of December 31, 2016.

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

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

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

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

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

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

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

Participants in the wholesale energy markets include:

- other utilities,
- federal power marketing agencies,
- energy marketing and trading companies,

- independent power producers,
- financial institutions, and
- commodity brokers.

Economic Conditions and Utility Load Growth

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

Avista Utilities

We track multiple economic indicators affecting the three largest metropolitan statistical areas in our Avista Utilities service area: Spokane, Washington, Coeur d'Alene, Idaho, and Medford, Oregon. Several key indicators are employment change, unemployment rates and foreclosure rates. On a year-over-year basis, December 2016 showed positive job growth and lower unemployment rates in all three metropolitan areas. However, the unemployment rates in Spokane and Medford are still above the national average. Except for Medford, foreclosure rates are in line with or below the U.S rate in all areas, and key leading indicators, initial unemployment claims and residential building permits signal continued growth over the next 12 months. Therefore, in 2017, we expect economic growth in our service area to be somewhat 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 December 2015 and December 2016. In Spokane, Washington employment growth was 3.6 percent with gains in all major sectors except manufacturing and leisure and hospitality. Employment increased by 2.5 percent in Coeur d'Alene, Idaho, reflecting gains in all major sectors except mining and logging and professional and business services. In Medford, Oregon, employment growth was 3.8 percent, with gains in all major sectors except mining and logging. U.S. nonfarm sector jobs grew by 1.5 percent in the same 12-month period.

Seasonally adjusted unemployment rates went down in December 2016 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the rate was 6.5 percent in December 2015 and declined to 6.3 percent in December 2016; in Coeur d'Alene the rate went from 4.9 percent to 4.5 percent; and in Medford the rate declined from 6.7 percent to 5.3 percent. The U.S. rate declined from 5.0 percent to 4.7 percent in the same period.

Except for the Medford area, the housing market in our Avista Utilities service area continues to experience foreclosure rates in line with the national average. The December 2016 national rate was 0.07 percent, compared to 0.07 percent in Spokane County, Washington; 0.02 percent in Kootenai County (Coeur d'Alene), Idaho; and 0.13 percent in Jackson County (Medford), Oregon.

Alaska Electric Light and Power Company

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

The Quarterly Census of Employment and Wages for Juneau shows employment declined 1.2 percent between second quarter 2015 and second quarter 2016. The employment decline was centered in government; construction; manufacturing; financial activities; and professional and business services. Government (including active duty military personnel) accounts for approximately 37 percent of total employment. Employment declines also occurred in natural resources and mining; education and health services; and other services. Between December 2015 and December 2016 the non-seasonally adjusted unemployment rate decreased from 4.7 percent to 4.5 percent.

The Juneau foreclosure rate is below the U.S. rate. The December 2016 rate was 0.02 percent compared to 0.07 percent for the U.S.

Forecasted Customer and Load Growth

Based on our forecast for 2017 through 2020 for Avista Utilities' service area, we expect annual electric customer growth to average 1.1 percent, within a forecast range of 0.7 percent to 1.5 percent. We expect annual natural gas customer growth to average 1.3 percent, within a forecast range of 0.8 percent to 1.8 percent. We anticipate retail electric load growth to average 0.6 percent, within a forecast range of 0.3 percent and 0.9 percent. We expect natural gas load growth to average 1.2 percent, within a forecast range of 0.7 percent and 1.7 percent. The forecast ranges reflect (1) the inherent uncertainty associated with the economic assumptions on which forecasts are based and (2) the historic variability of natural gas customer and load growth.

In AEL&P's service area, we expect residential customer growth near 0 percent (no residential customer growth) for 2017 through 2020. We also expect no significant growth in commercial and government customers over the same period. We anticipate average annual total load growth will be in a narrow range around 0.3 percent, with residential load growth averaging 0.6 percent, commercial growth near 0 percent (no load growth); and government growth near 0 percent.

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

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

Changes in actual experience can vary significantly from our projections.

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

Environmental Issues and Contingencies

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

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

Environmental laws and regulations may:

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

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

Clean Air Act (CAA)

We must comply with the requirements under the CAA in operating our thermal generating plants. The CAA currently requires a Title V operating permit for Colstrip (expires in 2017), Coyote Springs 2 (expires in 2018), the Kettle Falls GS (application has been made for a new permit), and the Rathdrum CT (application has been made for a new permit). Boulder Park GS, Northeast CT, and other activities only require minor source operating or registration permits based on their limited operation and emissions. The Title V operating permits are renewed every five years and updated to include newly applicable CAA requirements. We actively monitor legislative, regulatory and program developments within the CAA that may impact our facilities.

On March 6, 2013, the Sierra Club and Montana Environmental Information Center, filed a Complaint (Complaint) in the United States District Court for the District of Montana, Billings Division, against the owners of Colstrip. The Complaint alleged certain violations of the Clean Air Act. On July 12, 2016, all of the parties to this action filed a Consent Decree with the

Court settling all claims contained in the Complaint. See “Sierra Club and Montana Environmental Information Center Litigation” in “Note 19 of the Notes to Consolidated Financial Statements” for further information on this matter.

Hazardous Air Pollutants (HAPs)

The EPA regulates hazardous air pollutants from a published list of industrial sources referred to as "source categories" which must meet control technology requirements if they emit one or more of the pollutants in significant quantities. In 2012, the EPA finalized the Mercury Air Toxic Standards (MATS) for the coal and oil-fired source category. At the time of issuance in 2012, we examined the existing emission control systems of Colstrip Units 3 & 4, the only units in which we are a minority owner, and concluded that the existing emission control systems should be sufficient to meet mercury limits. For the remaining portion of the rule that utilized Particulate Matter as a surrogate for air toxics (including metals and acid gases), the Colstrip owners reviewed recent stack testing data and expected that no additional emission control systems would be needed for Units 3 & 4 MATS compliance.

Regional Haze Program

The EPA set a national goal of eliminating man-made visibility degradation in Class I areas by the year 2064. States are expected to take actions to make “reasonable progress” through 10-year plans, including application of Best Available Retrofit Technology (BART) requirements. BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In the case where a State opts out of implementing the Regional Haze program, the EPA may act directly. On September 18, 2012, the EPA finalized the Regional Haze federal implementation plan (FIP) for Montana. The FIP includes both emission limitations and pollution controls for Colstrip Units 1 & 2. Colstrip Units 3 & 4, the only units of which we are a minority owner, are not currently affected, but will be evaluated for Reasonable Progress at the next review period. We do not anticipate any material impacts on Units 3 & 4 at this time.

Coal Ash Management/Disposal

On April 17, 2015, the EPA published a final rule regarding coal combustion residuals (CCRs), also termed coal combustion byproducts or coal ash in the Federal Register, and this rule became effective on October 15, 2015. Colstrip, of which we are a 15 percent owner of Units 3 & 4, produces this byproduct. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. We, in conjunction with the other owners, are developing a multi-year compliance plan to strategically address the new CCR requirements and existing state obligations while maintaining operational stability. During 2015, the operator of Colstrip provided an initial cost estimate of the expected retirement costs associated with complying with the new CCR rule and based on the initial assessments, Avista Corp. recorded an increase to its asset retirement obligations of $12.5 million with a corresponding increase in the cost basis of the utility plant. During 2016, due to additional information and updated estimates, we increased the asset retirement obligation (ARO) to $13.6 million (including accretion of $0.7 million). See "Note 9 of the Notes to Consolidated Financial Statements" for additional information regarding AROs.

In addition to an increase to our ARO, it is expected that there will be significant compliance costs at Colstrip in the future, both operating and capital costs, due to a series of incremental infrastructure improvements which are separate from the ARO. Due to the preliminary nature of available data, we cannot reasonably estimate the future compliance costs; however, we will update our ARO and compliance cost estimates when 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 increased ARO due to uncertainty about the compliance strategies that will be used and the preliminary nature of available data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. We will coordinate with the plant operators and continue to gather additional data in future periods to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, we will update the ARO and future nonretirement compliance costs for these changes in estimates, which could be material. We expect to seek recovery of any increased costs related to complying with the new rule through customer rates.

Climate Change

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

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

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

Climate Change - Federal Regulatory Actions

The EPA released the final rules for the Clean Power Plan (Final CPP) and the Carbon Pollution Standards (Final CPS) on August 3, 2015. The Final CPP and the Final CPS are 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 on October 23, 2015 and were immediately challenged via lawsuits by other parties.

The Final CPP was promulgated pursuant to Section 111(d) of the CAA and applies to CO2 emissions from existing EGUs. The Final CPP is intended to reduce national CO2 emissions by approximately 32 percent below 2005 levels by 2030. The Final CPS rule was issued pursuant to Section 111(b) of the CAA and applies to the emissions of new, modified and reconstructed EGUs. The two rules are the first rules ever adopted by the U.S. federal government to comprehensively control and reduce CO2 emissions from the power sector. The EPA also issued a proposed Federal Implementation Plan (Proposed FIP) for the Final CPP. The Final FIP that the EPA adopts could be imposed on states by the EPA, should a state decide not to develop its own plan.

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

In a separate but related rulemaking, the EPA finalized CO2 new source performance standards (NSPS) for new, modified and reconstructed fossil fuel-fired EGUs under CAA section 111(b). These EGUs fall into the same two categories of sources regulated by the Final CPP: steam generating units (also known as “utility boilers and IGCC units”), which primarily burn coal, and stationary combustion turbines, which primarily burn natural gas.

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

The promulgated and proposed GHG rulemakings mentioned above have been legally challenged in multiple venues. On February 9, 2016, the U.S. Supreme Court granted a request for stay, halting implementation of the CPP. Given this development and related ongoing legal challenges, we cannot fully predict the outcome or estimate the extent to which our facilities may be impacted by these regulations at this time. We intend to seek recovery of any costs related to compliance with these requirements through the ratemaking process.

Climate Change - State Legislation and State Regulatory Activities

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

Washington and Oregon apply a GHG emissions performance standard (EPS) to electric generation facilities used to serve retail loads in their jurisdictions. 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 (Commerce) initiated a process to adopt a lower emissions performance standard in 2012; any new standard will be applicable until at least 2017. Commerce published a supplemental notice of proposed rulemaking on January 16, 2013 with a new EPS of 970 pounds of GHG per MWh. We will engage in the next process to revise the EPS, which should occur in 2017.

Washington

Energy Independence Act (EIA)

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

Clean Air Rule

In September 2016, the Washington State Department of Ecology (Ecology) adopted the Clean Air Rule (CAR) to cap and reduce GHG emissions across the State of Washington in pursuit of the State’s GHG goals, which were enacted in 2008 by the Washington State Legislature (Legislature). The CAR applies to sources of annual GHG emissions in excess of 100,000 tons for the first compliance period of 2017 through 2019; this threshold incrementally decreases to 70,000 metric tons beginning in 2035. The rule affects stationary sources and transportation fuel suppliers, as well as natural gas distribution companies. Ecology has identified approximately 30 entities that would be regulated under the CAR. Parties covered by the regulation must reduce emissions by 1.7 percent annually until 2035. Compliance can be demonstrated by achieving emission reductions and/or surrendering Emission Reduction Units (ERU), which are generated by parties that achieve reductions greater than required by the rule. ERUs can also take the form of renewable energy credits from renewable resources located in Washington, carbon emission offsets, and allowances acquired from an organized cap and trade market, such as that operating in California. In addition to the CAR's applicability to our burning of fuel as an electric utility, the CAR applies to us as a natural gas distribution company, for the emissions associated with the use of the natural gas we provide our customers who are not already covered under the regulation.

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

Petitioners believe that the reduction of GHG emissions is a matter that needs to be addressed, but the CAR is not the solution. Each utility represented in this case provided feedback and public comment to improve the rule, but ideas put forward were not incorporated in the final rule. They are asking the U.S District Court and the Thurston County Superior Court to find that the CAR is invalid.

In their State claim, Petitioners assert that:

- Ecology lacks statutory authority to regulate natural gas utilities because the CAR holds them responsible for the indirect emissions of their customers;
- Ecology does not have the authority to create an emission reduction trading program (ERUs);
- Ecology failed to comply with the requirements of the State Environmental Policy Act; and
- the CAR is arbitrary and capricious.

Petitioners' Federal claim asserts that the CAR violates the dormant Commerce Clause of the U.S. Constitution by discriminating against interstate commerce, regulating extraterritorially and unduly burdening interstate commerce by restricting the use of ERU’s (allowances) generated from outside Washington State for compliance purposes. The case in U.S. District Court has been tolled while the state court case proceeds, with oral arguments scheduled for the spring of 2017.

Initiative I-732

An Initiative to the Legislature (I-732) to impose a carbon tax on fossil-fueled generation and natural gas distribution, as well as on transportation fuels, was submitted to the Legislature in January 2016. The Legislature failed to act upon the measure and I-732 was referred to the November 2016 General Election ballot, where it failed to gain enough votes for enactment.

Colstrip 3 & 4 Considerations

On February 6, 2014, the UTC issued a letter finding that PSE's 2013 Electric Integrated Resource Plan meets the requirements of the Revised Code of Washington and the Washington Administrative Code. In its letter, however, the UTC expressed concern regarding the continued operation of the Colstrip plant as a resource to serve retail customers. Although the UTC recognized that the results of the analyses presented by PSE "differed significantly between [Colstrip] Units 1 & 2 and Units 3 & 4," the UTC did not limit its concerns solely to Colstrip Units 1 & 2. The UTC recommended that PSE "consult with UTC staff to consider a Colstrip Proceeding to determine the prudency of any new investment in Colstrip before it is made or, alternatively, a closure or partial-closure plan." As part of the Sierra Club litigation that was settled in 2016, Units 1 & 2 are scheduled to close by July 2022. See "Note 19 of the Notes to Consolidated Financial Statements" for further discussion of the Sierra Club litigation. As a 15 percent owner of Colstrip Units 3 & 4, we cannot estimate the effect of such proceeding, should it occur, on the future ownership, operation and operating costs of our share of Colstrip Units 3 & 4. Our remaining investment in Colstrip Units 3 & 4 as of December 31, 2016 was $131.0 million.

In Oregon, legislation was enacted in 2016 which requires Portland General Electric and PacifiCorp to remove coal-fired generation from their Oregon rate base by 2030. This legislation does not directly relate to Avista Corp. because Avista Corp. is not an electric utility in Oregon. However, because these two utilities, along with Avista Corp., hold minority interests in Colstrip, the legislation could indirectly impact Avista Corp., though specific impacts cannot be identified at this time. While the legislation requires Portland General Electric and PacifiCorp to eliminate Colstrip from their rates, they would be permitted to sell the output of their shares of Colstrip into the wholesale market or, as is the case with PacifiCorp, reallocate the plant to other states. We cannot predict the eventual outcome of actions arising from this legislation at this time or estimate the effect thereof on Avista Corp.; however, we will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to our generation assets.

Threatened and Endangered Species and Wildlife

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

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

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

Other

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

Enterprise Risk Management

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

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

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

Our primary identified categories of risk exposure are:

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

Financial Risk

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

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

Weather Risk

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

Access to Capital Markets

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

Interest Rate Risk

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

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

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

The following table summarizes our interest rate swap derivatives outstanding as of December 31, 2016 and December 31, 2015 (dollars in thousands):

	December 31, 2016	December 31, 2015
Number of agreements	33	23
Notional amount	$ 500,000	$ 455,000
Mandatory cash settlement dates	2017 to 2022	2016 to 2022
Short-term derivative assets (1)	$ 3,393	$ —
Long-term derivative assets (1)	5,357	23
Short-term derivative liability (1) (2)	(6,025)	(19,264)
Long-term derivative liability (1) (2)	(28,705)	(30,679)

(1) There are offsetting regulatory assets and liabilities for these items on the Consolidated Balance Sheets in accordance with regulatory accounting practices.
(2) The balance as of December 31, 2016 and December 31, 2015 reflects the offsetting of $34.9 million and $34.0 million, respectively, of cash collateral against the net derivative positions where a legal right of offset exists.

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

We estimated that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2015 would have decreased the interest rate swap derivative net liability by $9.8 million, while a 10-basis-point decrease would increase the interest rate swap derivative net liability by $10.1 million.

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

The following table shows our long-term debt (including current portion) and related weighted-average interest rates, by expected maturity dates as of December 31, 2016 (dollars in thousands):

	2017	2018	2019	2020	2021	Thereafter	Total	Fair Value
Fixed rate long-term debt (1)	$ —	$ 272,500	$ 105,000	$ 52,000	$ —	$ 1,198,500	$ 1,628,000	$ 1,723,912
Weighted-average interest rate	—	6.07%	5.22%	3.89%	—	4.91%	5.09%	
Variable rate long-term debt to affiliated trusts	—	—	—	—	—	$ 51,547	$ 51,547	$ 38,660
Weighted-average interest rate	—	—	—	—	—	1.81%	1.81%	

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

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

Credit Risk

Counterparty Non-Performance Risk

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

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

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

We seek to mitigate credit risk by:

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

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

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

Credit Risk Liquidity Considerations

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

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

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

As of December 31, 2016, we had cash deposited as collateral of $17.1 million and letters of credit of $24.4 million outstanding related to our energy derivative contracts. Price movements and/or a downgrade in our credit ratings could impact further the amount of collateral required. See "Credit Ratings" for further information. For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below "investment grade" based on our positions outstanding at December 31, 2016, we would potentially be required to post additional collateral of up to $6.0 million. This amount is different from the amount disclosed in “Note 6 of the Notes to Consolidated Financial Statements” because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 6, this analysis also takes into account contractual threshold limits that are not considered in Note 6. Without contractual threshold limits, we would potentially be required to post additional collateral of $8.2 million.

Under the terms of interest rate swap derivatives that we enter into periodically, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. As of December 31, 2016, we had interest rate swap agreements outstanding with a notional amount totaling $500.0 million and we had deposited cash in the amount of $34.9 million and letters of credit of $3.6 million as collateral for these interest rate swap derivatives. If our credit ratings were lowered to below “investment grade” based on our interest rate swap derivatives outstanding at December 31, 2016, we would have to post $21.1 million of additional collateral.

Foreign Currency Risk

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

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

Utility Regulatory Risk

Because we are primarily a regulated utility, we face the risk that regulators may not grant rates that provide timely or sufficient recovery of our costs or allow a reasonable rate of return for our shareholders. This includes costs associated with our investment in rate base, as well as commodity costs and other operating and financing expenses. During December 2016, the UTC denied our most recent electric and natural gas general rate requests and granted zero rate relief. We are currently in the process of pursuing remedies toward a reasonable end result. If our efforts to obtain rates that are fair, just, reasonable and sufficient are not successful, we expect our 2017 earnings will be adversely impacted. See further discussion at "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Regulatory Matters."

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

Energy Commodity Risk

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

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

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

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

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

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

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2016 that are expected to settle in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2017	$ (4,274)	$ 1,939	$ 97	$ (4,005)	$ (225)	$ 576	$ (2,036)	$ (3,440)
2018	(5,598)	—	—	(2,170)	(33)	854	(910)	709
2019	(3,123)	—	(235)	(3,732)	(40)	975	(927)	103
2020	—	—	(266)	(370)	—	—	(1,288)	—
2021	—	—	—	—	—	—	(869)	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2015 that were expected to settle in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2016	$ (6,928)	$ (14,988)	$ (5,895)	$ (41,006)	$ 82	$ 28,857	$ 173	$ 22,445
2017	(6,403)	36	(1,050)	(9,473)	(23)	3,971	(1,125)	313
2018	(5,614)	—	—	(3,554)	(50)	—	(1,172)	(162)
2019	(3,072)	—	(22)	(1,964)	(44)	—	(1,220)	—
2020	—	—	35	(18)	—	—	(1,130)	—
Thereafter	—	—	—	—	—	—	(679)	—

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

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

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

Operational Risk

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

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

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

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

Compliance Risk

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

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

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

Technology Risk

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

We mitigate technology risk through trainings and exercises at all levels of the Company. The Environmental, Technology and Operations Committee of our Board of Directors along with senior management are regularly briefed on security policy, programs and incidents. Annual cyber and physical training and testing of employees are included in our enterprise security program as are business continuity testing and data breach response exercises.

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

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

Strategic Risk

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

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

External Mandates Risk

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

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

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Avista Corporation and subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report, dated February 21, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 21, 2017

CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

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

	2016	2015	2014
Operating Revenues:			
Utility revenues	$ 1,418,914	$ 1,456,091	$ 1,433,343
Non-utility revenues	23,569	28,685	39,219
Total operating revenues	1,442,483	1,484,776	1,472,562
Operating Expenses:			
Utility operating expenses:			
Resource costs	551,366	656,964	678,244
Other operating expenses	315,795	303,221	286,832
Depreciation and amortization	160,514	143,499	129,570
Taxes other than income taxes	98,735	97,657	94,300
Non-utility operating expenses:			
Other operating expenses	25,501	29,526	30,418
Depreciation and amortization	769	695	610
Total operating expenses	1,152,680	1,231,562	1,219,974
Income from operations	289,803	253,214	252,588
Interest expense	86,496	79,968	75,302
Interest expense to affiliated trusts	634	473	450
Capitalized interest	(2,651)	(3,546)	(3,924)
Other income-net	(10,078)	(9,300)	(11,346)
Income from continuing operations before income taxes	215,402	185,619	192,106
Income tax expense	78,086	67,449	72,240
Net income from continuing operations	137,316	118,170	119,866
Net income from discontinued operations (Note 5)	—	5,147	72,411
Net income	137,316	123,317	192,277
Net income attributable to noncontrolling interests	(88)	(90)	(236)
Net income attributable to Avista Corp. shareholders	$ 137,228	$ 123,227	$ 192,041

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF INCOME (continued)

Avista Corporation

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

	2016	2015	2014
Amounts attributable to Avista Corp. shareholders:			
Net income from continuing operations	$ 137,228	$ 118,080	$ 119,817
Net income from discontinued operations	—	5,147	72,224
Net income attributable to Avista Corp. shareholders	$ 137,228	$ 123,227	$ 192,041
Weighted-average common shares outstanding (thousands), basic	63,508	62,301	61,632
Weighted-average common shares outstanding (thousands), diluted	63,920	62,708	61,887
Earnings per common share attributable to Avista Corp. shareholders, basic:			
Earnings per common share from continuing operations	$ 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	$ 2.16	$ 1.98	$ 3.12
Earnings per common share attributable to Avista Corp. shareholders, diluted:			
Earnings per common share from continuing operations	$ 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	$ 2.15	$ 1.97	$ 3.10
Dividends declared per common share	$ 1.37	$ 1.32	$ 1.27

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Years Ended December 31
Dollars in thousands

	2016	2015	2014
Net income	$ 137,316	$ 123,317	$ 192,277
Other Comprehensive Income (Loss):			
Unrealized investment gains - net of taxes of $0, $0 and $664, respectively	—	—	1,126
Reclassification adjustment for realized gains on investment securities included in net income - net of taxes of $0, $0 and $(1), respectively	—	—	(2)
Reclassification adjustment for realized losses on investment securities included in net income from discontinued operations - net of taxes of $0, $0 and $273, respectively	—	—	462
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $(495), $667 and $(1,967), respectively	(918)	1,238	(3,655)
Total other comprehensive income (loss)	(918)	1,238	(2,069)
Comprehensive income	136,398	124,555	190,208
Comprehensive income attributable to noncontrolling interests	(88)	(90)	(236)
Comprehensive income attributable to Avista Corporation shareholders	$ 136,310	$ 124,465	$ 189,972

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS

Avista Corporation

As of December 31
Dollars in thousands

	2016	2015
Assets:		
Current Assets:		
Cash and cash equivalents	$ 8,507	$ 10,484
Accounts and notes receivable-less allowances of $5,026 and $4,530, respectively	180,265	169,413
Regulatory asset for energy commodity derivatives	11,365	17,260
Materials and supplies, fuel stock and stored natural gas	53,314	54,148
Income taxes receivable	48,265	24,121
Other current assets	49,625	30,620
Total current assets	351,341	306,046
Net Utility Property:		
Utility plant in service	5,506,499	5,129,192
Construction work in progress	150,474	202,683
Total	5,656,973	5,331,875
Less: Accumulated depreciation and amortization	1,509,473	1,433,286
Total net utility property	4,147,500	3,898,589
Other Non-current Assets:		
Investment in affiliated trusts	11,547	11,547
Goodwill	57,672	57,672
Long-term energy contract receivable	—	14,694
Other property and investments-net and other non-current assets	72,224	59,733
Total other non-current assets	141,443	143,646
Deferred Charges:		
Regulatory assets for deferred income tax	109,853	101,240
Regulatory assets for pensions and other postretirement benefits	240,114	235,009
Other regulatory assets	135,751	99,798
Regulatory asset for interest rate swaps	161,508	83,973
Non-current regulatory asset for energy commodity derivatives	16,919	32,420
Other deferred charges	5,326	5,928
Total deferred charges	669,471	558,368
Total assets	$ 5,309,755	$ 4,906,649

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

As of December 31

Dollars in thousands

	2016	2015
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 115,545	$ 114,349
Current portion of long-term debt and capital leases	3,287	93,167
Short-term borrowings	120,000	105,000
Energy commodity derivative liabilities	7,035	14,268
Accrued interest	15,869	15,378
Accrued taxes other than income taxes	33,374	30,978
Deferred natural gas costs	30,820	17,880
Current portion of pensions and other postretirement benefits	10,994	10,233
Other current liabilities	70,604	73,427
Total current liabilities	407,528	474,680
Long-term debt and capital leases	1,678,717	1,480,111
Long-term debt to affiliated trusts	51,547	51,547
Regulatory liability for utility plant retirement costs	273,983	261,594
Pensions and other postretirement benefits	226,552	201,453
Deferred income taxes	840,928	747,477
Non-current interest rate swap derivative liabilities	28,705	30,679
Other non-current liabilities, regulatory liabilities and deferred credits	153,319	130,821
Total liabilities	3,661,279	3,378,362
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Equity:		
Avista Corporation Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 64,187,934 and 62,312,651 shares issued and outstanding as of December 31, 2016 and December 31, 2015, respectively	1,075,281	1,004,336
Accumulated other comprehensive loss	(7,568)	(6,650)
Retained earnings	581,014	530,940
Total Avista Corporation shareholders' equity	1,648,727	1,528,626
Noncontrolling Interests	(251)	(339)
Total equity	1,648,476	1,528,287
Total liabilities and equity	$ 5,309,755	$ 4,906,649

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Years Ended December 31
Dollars in thousands

	2016	2015	2014
Operating Activities:			
Net income	$ 137,316	$ 123,317	$ 192,277
Non-cash items included in net income:			
Depreciation and amortization	164,925	147,835	138,337
Provision for deferred income taxes	124,543	51,801	144,269
Power and natural gas cost amortizations (deferrals), net	16,835	21,358	(14,821)
Amortization of debt expense	3,477	3,526	3,692
Amortization of investment in exchange power	2,450	2,450	2,450
Stock-based compensation expense	7,891	6,914	8,114
Equity-related AFUDC	(8,475)	(8,331)	(8,808)
Pension and other postretirement benefit expense	38,786	37,050	22,943
Amortization of Spokane Energy contract	14,694	13,508	12,417
Gain on sale of Ecova	—	(777)	(160,612)
Other regulatory assets and liabilities and deferred debits and credits	(26,245)	4,569	7,906
Change in decoupling regulatory deferral	(29,789)	(10,933)	—
Other	5,557	(517)	1,103
Contributions to defined benefit pension plan	(12,000)	(12,000)	(32,000)
Cash paid for settlement of interest rate swap derivatives	(53,966)	—	—
Changes in certain current assets and liabilities:			
Accounts and notes receivable	(17,170)	(10,538)	16,425
Materials and supplies, fuel stock and stored natural gas	834	12,208	(19,394)
Collateral posted for derivative instruments	10,712	(13,301)	(23,301)
Income taxes receivable	(33,923)	19,772	(36,110)
Other current assets	(3,907)	2,338	(7,117)
Accounts payable	5,176	(8,138)	(12,562)
Other current liabilities	10,546	(6,471)	32,060
Net cash provided by operating activities	358,267	375,640	267,268
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(406,644)	(393,425)	(325,516)
Other capital expenditures	(353)	(885)	(6,427)
Cash received (paid) in acquisition, net	—	(95)	15,007
Issuance of notes receivable at subsidiaries	(10,094)	(2,307)	(1,200)
Repayments from notes receivable at subsidiaries	5,000	—	—
Investments made by subsidiaries	(13,097)	(1,944)	(1,072)
Increase in funds held for clients	—	—	(18,931)
Purchase of securities available for sale	—	—	(12,267)
Sale and maturity of securities available for sale	—	—	14,612
Proceeds from sale of Ecova, net of cash sold	—	13,856	229,903
Other	(7,278)	(3,027)	2,155
Net cash used in investing activities	$ (432,466)	$ (387,827)	$ (103,736)

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

For the Years Ended December 31
Dollars in thousands

	2016	2015	2014
Financing Activities:			
Net increase (decrease) in borrowings from committed line of credit	$ 15,000	$ —	$ (66,000)
Repayment of borrowings from Ecova line of credit	—	—	(46,000)
Proceeds from issuance of long-term debt	245,000	100,000	150,000
Redemption and maturity of long-term debt and capital leases	(163,167)	(2,905)	(39,971)
Maturity of nonrecourse long-term debt of Spokane Energy	—	(1,431)	(16,407)
Issuance of common stock, net of issuance costs	66,953	1,560	4,060
Repurchase of common stock	—	(2,920)	(79,856)
Cash dividends paid	(87,154)	(82,397)	(78,314)
Increase in client fund obligations	—	—	16,216
Payment to noncontrolling interests for sale of Ecova	—	—	(54,179)
Payment to option holders and redeemable noncontrolling interests for sale of Ecova	—	—	(20,871)
Other	(4,410)	(11,379)	7,359
Net cash provided by (used in) financing activities	72,222	528	(223,963)
Net decrease in cash and cash equivalents	(1,977)	(11,659)	(60,431)
Cash and cash equivalents at beginning of year	10,484	22,143	82,574
Cash and cash equivalents at end of year	$ 8,507	$ 10,484	$ 22,143
Supplemental Cash Flow Information:			
Cash paid (received) during the year:			
Interest	$ 86,319	$ 79,673	$ 73,526
Income taxes (net of total refunds of $18,861, $37,200 and $35,573, respectively)	(13,458)	(9,961)	45,416
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	30,252	35,248	26,959
Valuation adjustment for redeemable noncontrolling interests	—	—	(15,873)
Receivable for escrow amounts associated with the sale of Ecova	—	—	13,079
Non-cash stock issuance for acquisition of AERC	—	—	150,119

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

For the Years Ended December 31
Dollars in thousands

	2016	2015	2014
Common Stock, Shares:			
Shares outstanding at beginning of year	62,312,651	62,243,374	60,076,752
Shares issued through equity compensation plans	203,727	125,620	51,127
Shares issued through Employee Investment Plan (401-K)	26,556	33,057	33,168
Shares issued through Dividend Reinvestment Plan	—	—	110,501
Shares issued through sales agency agreements	1,645,000	—	—
Shares issued for acquisition	—	—	4,501,441
Shares repurchased	—	(89,400)	(2,529,615)
Shares outstanding at end of year	64,187,934	62,312,651	62,243,374
Common Stock, Amount:			
Balance at beginning of year	$ 1,004,336	$ 999,960	$ 896,993
Equity compensation expense	7,065	6,035	7,676
Issuance of common stock through equity compensation plans	624	462	108
Issuance of common stock through Employee Investment Plan (401-K)	1,061	1,099	1,005
Issuance of common stock through Dividend Reinvestment Plan	—	—	3,441
Issuance of common stock through sales agency agreements, net of issuance costs	65,267	—	—
Issuance of common stock for acquisition, net of issuance costs	—	—	149,625
Payment of minimum tax withholdings for share-based payment awards	(3,072)	(1,832)	—
Repurchase of common stock	—	(1,431)	(40,486)
Equity transactions of consolidated subsidiaries	—	—	(1,062)
Payment to option holders and redeemable noncontrolling interests for sale of Ecova	—	—	(20,871)
Excess tax benefits	—	43	3,531
Balance at end of year	1,075,281	1,004,336	999,960
Accumulated Other Comprehensive Loss:			
Balance at beginning of year	(6,650)	(7,888)	(5,819)
Other comprehensive income (loss)	(918)	1,238	(2,069)
Balance at end of year	(7,568)	(6,650)	(7,888)
Retained Earnings:			
Balance at beginning of year	530,940	491,599	407,092
Net income attributable to Avista Corporation shareholders	137,228	123,227	192,041
Cash dividends paid (common stock)	(87,154)	(82,397)	(78,314)
Repurchase of common stock	—	(1,489)	(39,370)
Valuation adjustments and other noncontrolling interests activity	—	—	10,150
Balance at end of year	581,014	530,940	491,599
Total Avista Corporation shareholders' equity	$ 1,648,727	$ 1,528,626	$ 1,483,671

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS (continued)

Avista Corporation

For the Years Ended December 31
Dollars in thousands

	2016	2015	2014
Noncontrolling Interests:			
Balance at beginning of year	$ (339)	$ (429)	$ 20,001
Net income attributable to noncontrolling interests	88	90	240
Deconsolidation of noncontrolling interests related to sale of Ecova	—	—	(23,612)
Other	—	—	2,942
Balance at end of year	(251)	(339)	(429)
Total equity	$ 1,648,476	$ 1,528,287	$ 1,483,242
Redeemable Noncontrolling Interests:			
Balance at beginning of year	$ —	$ —	$ 15,889
Net income attributable to noncontrolling interests	—	—	(4)
Purchase of subsidiary noncontrolling interests	—	—	(12)
Valuation adjustments and other noncontrolling interests activity	—	—	(15,873)
Balance at end of year	$ —	$ —	$ —

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

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

AERC is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is AEL&P, which comprises Avista Corp.'s regulated utility operations in Alaska. AERC was acquired by Avista Corp. on July 1, 2014 and there are no AERC earnings included in the overall results of Avista Corp. prior to that date. See Note 4 for information regarding the acquisition of AERC.

Avista Capital, a wholly owned non-regulated subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility businesses, with the exception of AJT Mining Properties, which is a subsidiary of AERC. During the first half of 2014 and prior, Avista Capital’s subsidiaries included Ecova, which was an 80.2 percent owned subsidiary prior to its disposition on June 30, 2014. See Note 5 for information regarding the disposition of Ecova and Note 21 for business segment information.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Ecova's revenues and expenses are included in the Consolidated Statements of Income in discontinued operations; however, as of June 30, 2014 and for all subsequent reporting periods there are no balance sheet amounts included for Ecova. All tables throughout the Notes to Consolidated Financial Statements that present information related to the Consolidated Statements of Income were revised to include only the amounts from continuing operations. Intercompany balances were eliminated in consolidation. The accompanying consolidated financial statements include the Company’s proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 7).

Use of Estimates

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

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

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

System of Accounts

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

Regulation

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

Utility Revenues

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

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

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

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

	2016	2015
Unbilled accounts receivable	$ 72,377	$ 62,003

Other Non-Utility Revenues

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

Depreciation

For utility operations, depreciation expense is estimated by a method of depreciation accounting utilizing composite rates for utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives. For utility operations, the ratio of depreciation provisions to average depreciable property was as follows for the years ended December 31:

	2016	2015	2014
Avista Utilities			
Ratio of depreciation to average depreciable property	3.11%	3.09%	2.97%
Alaska Electric Light and Power Company			
Ratio of depreciation to average depreciable property	2.39%	2.42%	2.43%

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

	Avista Utilities	Alaska Electric Light and Power Company
Electric thermal/other production	41	41
Hydroelectric production	78	42
Electric transmission	57	41
Electric distribution	35	40
Natural gas distribution property	45	N/A
Other shorter-lived general plant	9	15

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense. Taxes other than income taxes consisted of the following items for the years ended December 31 (dollars in thousands):

	2016	2015	2014
Utility related taxes	$ 57,745	$ 59,173	$ 58,250
Property taxes	38,505	35,948	33,932
Other taxes	2,485	2,536	2,118
Total	$ 98,735	$ 97,657	$ 94,300

Allowance for Funds Used During Construction

AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. As prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant. The debt component of AFUDC is credited against total interest expense in the Consolidated Statements of Income in the line item "capitalized interest." The equity component of AFUDC is included in the Consolidated Statement of Income in the line item "other income-net." The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was the following for the years ended December 31:

	2016	2015	2014
Avista Utilities			
Effective AFUDC rate	7.29%	7.32%	7.64%
Alaska Electric Light and Power Company			
Effective AFUDC rate	9.40%	9.31%	10.37%

Income Taxes

Deferred income tax assets represent future income tax deductions the Company expects to utilize in future tax returns to reduce taxable income. Deferred income tax liabilities represent future taxable income the Company expects to recognize in future tax returns. Deferred tax assets and liabilities arise when there are temporary differences resulting from differing treatment of items for tax and accounting purposes (such as depreciation). A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the temporary differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company's consolidated income tax returns. The deferred income tax expense for the period is equal to the net change in the deferred income tax asset and liability accounts from the beginning to the end of the period. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the enactment date unless a regulatory order specifies deferral of the effect of the change in tax rates over a longer period of time. The Company establishes a valuation allowance when it is more likely than not that all, or a portion, of a deferred tax asset will not be realized. Deferred income tax liabilities and regulatory assets are established for income tax benefits flowed through to customers. The Company did not incur any penalties on income tax positions in 2016, 2015 or 2014. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

Stock-Based Compensation

The Company currently issues three types of stock-based compensation awards - restricted shares, market-based awards and performance-based awards. Historically, these stock compensation awards have not been material to the Company's overall financial results. Compensation cost relating to share-based payment transactions is recognized in the Company's financial statements based on the fair value of the equity or liability instruments issued and recorded over the requisite service period.

The Company recorded stock-based compensation expense (included in other operating expenses) and income tax benefits in the Consolidated Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2016	2015	2014
Stock-based compensation expense	$ 7,891	$ 6,914	$ 6,007
Income tax benefits (1)	4,359	2,420	2,102

(1) Income tax benefits for 2016 include $1.6 million associated with excess tax benefits on settled share-based employee payments. The excess tax benefits were recognized in the Statement of Income for 2016 due to the adoption of ASU 2016-09, effective January 1, 2016. See Note 2 for further discussion.

Restricted share awards vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the Chief Executive Officer's restricted shares to vest. Restricted stock is valued at the close of market of the Company's common stock on the grant date.

Total Shareholder Return (TSR) awards are market-based awards and Cumulative Earnings Per Share (CEPS) awards are performance awards. CEPS awards were first granted in 2014. Both types of awards vest after a period of three years and are payable in cash or Avista Corp. common stock at the end of the three-year period. The method of settlement is at the discretion of the Company and historically the Company has settled these awards through issuance of Avista Corp. common stock and intends to continue this practice. Both types of awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific market or performance conditions. Based on the level of attainment of the market or performance conditions, the amount of cash paid or common stock issued will range from 0 to 200 percent of the initial awards granted. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest and have met the market and performance conditions.

For both the TSR awards and the CEPS awards, the Company accounts for them as equity awards and compensation cost for these awards is recognized over the requisite service period, provided that the requisite service period is rendered. For TSR awards, if the market condition is not met at the end of the three-year service period, there will be no change in the cumulative amount of compensation cost recognized, since the awards are still considered vested even though the market metric was not met. For CEPS awards, at the end of the three-year service period, if the internal performance metric of cumulative earnings per share is not met, all compensation cost for these awards is reversed as these awards are not considered vested.

The fair value of each TSR award is estimated on the date of grant using a statistical model that incorporates the probability of meeting the market targets based on historical returns relative to a peer group. The estimated fair value of the equity component of CEPS awards was estimated on the date of grant as the share price of Avista Corp. common stock on the date of grant, less the net present value of the estimated dividends over the three-year period.

The following table summarizes the number of grants, vested and unvested shares, earned shares (based on market metrics), and other pertinent information related to the Company's stock compensation awards for the years ended December 31:

	2016	2015	2014
Restricted Shares			
Shares granted during the year	58,610	58,302	62,075
Shares vested during the year	(52,385)	(60,379)	(52,899)
Unvested shares at end of year	109,806	106,091	112,042
Unrecognized compensation expense at end of year (in thousands)	$ 1,853	$ 1,705	$ 1,349
TSR Awards			
TSR shares granted during the year	116,435	116,435	117,550
TSR shares vested during the year	(111,665)	(171,334)	(167,584)
TSR shares earned based on market metrics	132,887	222,734	97,199
Unvested TSR shares at end of year	222,228	223,697	287,834
Unrecognized compensation expense (in thousands)	$ 3,409	$ 3,219	$ 2,833
CEPS Awards			
CEPS shares granted during the year	57,521	58,259	59,025
CEPS shares vested during the year	(55,835)	—	—
CEPS shares earned based on market metrics	90,460	—	—
Unvested CEPS shares at end of year	110,452	111,887	58,017
Unrecognized compensation expense (in thousands)	$ 1,671	$ 1,840	$ 1,577

Outstanding TSR and CEPS share awards include a dividend component that is paid in cash. This component of the share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, the change in the value of the Company’s common stock relative to an external benchmark (TSR awards only) and the amount of CEPS earned to date compared to estimated CEPS over the performance period (CEPS awards only). Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2016 and 2015, the Company had recognized cumulative compensation expense and a liability of $1.5 million, respectively, related to the dividend component on the outstanding and unvested share grants.

Other Income - Net

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

	2016	2015	2014
Interest income	$ 1,823	$ 653	$ 987
Interest on regulatory deferrals	1,308	48	220
Equity-related AFUDC	8,475	8,331	8,808
Net gain (loss) on investments	(2,152)	(637)	276
Other income	624	905	1,055
Total	$ 10,078	$ 9,300	$ 11,346

Earnings per Common Share Attributable to Avista Corporation Shareholders

Basic earnings per common share attributable to Avista Corp. shareholders is computed by dividing net income attributable to Avista Corp. shareholders by the weighted-average number of common shares outstanding for the period. Diluted earnings per common share attributable to Avista Corp. shareholders is calculated by dividing net income attributable to Avista Corp. shareholders (adjusted for the effect of potentially dilutive securities issued to noncontrolling interests by the Company's subsidiaries) by diluted weighted-average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable upon exercise of stock options and contingent stock awards. See Note 18 for earnings per common share calculations.

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts to provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts. The following table presents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in thousands):

	2016	2015	2014
Allowance as of the beginning of the year	$ 4,530	$ 4,888	$ 44,309
Additions expensed during the year	6,053	5,802	5,296
Net deductions (1)	(5,557)	(6,160)	(44,717)
Allowance as of the end of the year	$ 5,026	$ 4,530	$ 4,888

(1) During 2014, the Company received $15.0 million in gross proceeds related to the settlement of its California wholesale power markets litigation. The gross proceeds effectively settled all outstanding receivables and payables at Avista Energy (which had been fully reserved against since 2001). As a result of the settlement, the Company reversed $15.0 million of the allowance, which was recorded as a reduction to non-utility other operating expenses on the Consolidated Statements of Income, and the remainder of the receivables, payables and allowance of $24.5 million were removed from the Consolidated Balance Sheets (and had no effect on net income).

Materials and Supplies, Fuel Stock and Stored Natural Gas

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

	2016	2015
Materials and supplies	$ 40,700	$ 37,101
Fuel stock	4,585	4,273
Stored natural gas	8,029	12,774
Total	$ 53,314	$ 54,148

Utility Plant in Service

The cost of additions to utility plant in service, including an allowance for funds used during construction and replacements of units of property and improvements, is capitalized. The cost of depreciable units of property retired plus the cost of removal less salvage is charged to accumulated depreciation.

Asset Retirement Obligations

The Company records the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the associated costs of the ARO are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. In addition, if there are changes in the estimated timing or estimated costs of the AROs, adjustments are recorded during the period new information becomes available as an increase or decrease to the liability, with the offset recorded to the related long-lived asset. Upon retirement of the asset, the Company either settles the ARO for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers (see Note 9 for further discussion of the Company's asset retirement obligations).

The Company recovers certain asset retirement costs through rates charged to customers as a portion of its depreciation expense for which the Company has not recorded asset retirement obligations. The Company has recorded the amount of estimated retirement costs collected from customers (that do not represent legal or contractual obligations) and included them as a regulatory liability on the Consolidated Balance Sheets in the following amounts as of December 31 (dollars in thousands):

	2016	2015
Regulatory liability for utility plant retirement costs	$ 273,983	$ 261,594

Goodwill

Goodwill arising from acquisitions represents the future economic benefit arising from other assets acquired in a business combination that are not individually identified and separately recognized. The Company evaluates goodwill for impairment using a qualitative analysis (Step 0) for AEL&P and a combination of discounted cash flow models and a market approach for the other subsidiaries on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2016 and determined that goodwill was not impaired at that time.

The changes in the carrying amount of goodwill are as follows (dollars in thousands):

	AEL&P	Other	Accumulated Impairment Losses	Total
Balance as of January 1, 2015	$ 52,730	$ 12,979	$ (7,733)	$ 57,976
Adjustments	(304)	—	—	(304)
Balance as of the December 31, 2015	52,426	12,979	(7,733)	57,672
Balance as of the December 31, 2016	$ 52,426	$ 12,979	$ (7,733)	$ 57,672

Accumulated impairment losses are attributable to the other businesses. The goodwill adjustments recorded during 2015 relate to the final true-up of income taxes associated with the acquisition of AERC, which occurred on July 1, 2014. See Note 4 for information regarding this business acquisition and Note 21 regarding the Company's reportable segments.

Derivative Assets and Liabilities

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

The UTC and the IPUC issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. Realized benefits and costs result in adjustments to retail rates through PGAs, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases. The resulting regulatory assets have been concluded to be probable of recovery through future rates.

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

For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process.

As of December 31, 2016, the Company has multiple master netting agreements with a variety of entities that allow for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have any agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The Company nets all derivative instruments when allowed by the agreement for presentation in the Consolidated Balance Sheets.

Fair Value Measurements

Fair value represents the price that would be received when selling an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swap derivatives and foreign currency exchange derivatives, are reported at estimated fair value on the Consolidated Balance Sheets. See Note 16 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

The Company prepares its consolidated financial statements in accordance with regulatory accounting practices because:

- rates for regulated services are established by or subject to approval by independent third-party regulators,
- the regulated rates are designed to recover the cost of providing the regulated services, and
- in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates can be charged to and collected from customers at levels that will recover costs.

Regulatory accounting practices require that certain costs and/or obligations (such as incurred power and natural gas costs not currently included in rates, but expected to be recovered or refunded in the future), are reflected as deferred charges or credits on the Consolidated Balance Sheets. These costs and/or obligations are not reflected in the Consolidated Statements of Income until the period during which matching revenues are recognized. The Company also has decoupling revenue deferrals. Decoupling revenue deferrals are recognized in the Consolidated Statements of Income during the period they occur (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset/liability is established which will be surcharged or rebated to customers in future periods. GAAP requires that for any alternative regulatory revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the current period Consolidated Statement of Income. Any amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. This could ultimately result in decoupling revenue being recognized in a future period.

If at some point in the future the Company determines that it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

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

See Note 20 for further details of regulatory assets and liabilities.

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt. These costs are recorded as an offset to Long-Term Debt and Capital Leases on the Consolidated Balance Sheets.

Unamortized Debt Repurchase Costs

For the Company's Washington regulatory jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. These costs are recovered through retail rates as a component of interest expense.

Accumulated Other Comprehensive Loss

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

	2016	2015
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $4,075 and $3,580, respectively	$ 7,568	$ 6,650

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

Details about Accumulated Other Comprehensive Loss Components	Amounts Reclassified from Accumulated Other Comprehensive Loss 2016	2015	2014	Affected Line Item in Statement of Income
Realized gains on investment securities	$ —	$ —	$ (3)	(a)
Realized losses on investment securities	—	—	735	(a)
	—	—	732	Total before tax
	—	—	(272)	Tax expense (a)
	$ —	$ —	$ 460	Net of tax
Amortization of defined benefit pension items				
Amortization of net prior service cost	$ (1,171)	$ 31	$ (1,094)	(b)
Amortization of net loss	(7,602)	2,623	(83,301)	(b)
Adjustment due to effects of regulation	7,360	(749)	78,773	(b)
	(1,413)	1,905	(5,622)	Total before tax
	495	(667)	1,967	Tax benefit (expense)
	$ (918)	$ 1,238	$ (3,655)	Net of tax

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

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

Appropriated Retained Earnings

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

In addition to the hydroelectric project licenses identified above for Avista Utilities, the requirements of section 10(d) of the FPA also apply to the AEL&P licenses for Lake Dorothy and Annex Creek/Salmon Creek (combined).

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

	2016	2015
Appropriated retained earnings	$ 25,564	$ 21,030

Operating Leases

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from 1 to 45 years. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year were not material as of December 31, 2016.

Capital Leases

The Company has two capital leases, one at Avista Corp. and one at AEL&P. The capital lease at Avista Corp. expires in 2018 and is not material to the financial statements as of December 31, 2016. The capital lease at AEL&P is a PPA (treated as a lease for accounting purposes) related to the Snettisham Hydroelectric Project that expires in 2034. While the two leases are treated as capital leases for accounting purposes, for ratemaking purposes these agreements are treated as operating leases with a constant level of annual rental expense (straight line expense). Because of this regulatory treatment, any difference between the operating lease expense for ratemaking purposes and the expenses recognized under capital lease treatment (interest and depreciation of the capital lease asset) is recorded as a regulatory asset and amortized during the later years of the lease when the capital lease expense is less than the operating lease expense included in base rates. See Note 14 for further discussion of the Snettisham capital lease.

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses losses that do not meet these conditions for accrual, if there is a reasonable possibility that a material loss may be incurred. As of December 31, 2016, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 19 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)"

In May 2014, the FASB issued ASU No. 2014-09, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity should identify the various performance obligations in a contract, allocate the transaction price among the performance obligations and recognize revenue when (or as) the entity satisfies each performance obligation. This ASU was originally effective for periods beginning after December 15, 2016 and early adoption was not permitted. In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU No. 2014-09 for one year, with adoption as of the original date permitted.

The Company has formed a revenue recognition standard implementation team that is working through several implementation issues described below. The Company has evaluated this standard and is planning to adopt this standard in 2018 upon its effective date. The Company is currently expecting to use a modified retrospective method of adoption, which would require a cumulative adjustment to opening retained earnings, as opposed to a full retrospective application. The Company is not far enough along in the adoption process to determine the amount, if any, of cumulative adjustment necessary.

Since the vast majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers and revenue is recognized as energy is delivered to these customers, the Company does not expect a significant change in operating revenues or net income. The Company is in the process of reviewing and analyzing certain contracts with customers (most of which are related to wholesale sales of power and natural gas), but has not yet identified any significant differences in revenue recognition between current GAAP and ASU 2014-09.

During the implementation process, the Company has identified several unresolved issues, the most significant of which are as follows based on our current assessment:

Contributions in Aid of Construction – There is the potential that CIACs could be recognized as revenue upon the adoption of ASU 2014-09. Under current GAAP, CIACs are accounted for as an offset to the cost of utility plant in service.

Utility Related Taxes Collected from Customers – There are questions on the presentation of utility related taxes collected from customers (primarily state excise taxes and city utility taxes) on a gross basis. Under current GAAP, the Company is allowed to record these utility related taxes on a gross basis in revenue when billed to customers with an offset included in taxes other than income taxes in operating expenses. The Company is evaluating whether this presentation is appropriate under ASU 2014-09 or whether they should be presented on a net basis. To qualify for gross presentation under the new guidance, the Company must perform an analysis to determine if it is the principal or the agent in regards to utility related taxes.

Collectibility - There are questions regarding the requirement that collection of a sale be probable and how, or if, utilities should consider bad debt collection mechanisms (riders, base rate adjustments, etc.) in assessing probability of collection on sales to low income customers. Within the utility industry, there is support for and against considering these recovery mechanisms when assessing collectibility of a sale. If the bad debt recovery mechanisms cannot be considered, there is the potential that certain sales to low income customers cannot be recognized as revenue until payment is received from the customers, which could result in revenues being recognized in periods other than when the energy was delivered to customers or not recognized at all.

The Company is monitoring utility industry implementation guidance as it relates to unresolved issues to determine if there will be an industry consensus regarding accounting and presentation of these items.

ASU No. 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis"

In February 2015, the FASB issued ASU No. 2015-02. This ASU changes the consolidation analysis required under GAAP, including the identification of variable interest entities (VIE). The ASU also removes the deferral of the VIE analysis related to investments in certain investment funds, which results in a different consolidation evaluation for these types of investments. The Company adopted this standard effective January 1, 2016. The adoption of this standard resulted in the identification of several Avista Corp. investments in limited partnerships (or a functional equivalent) that are now considered VIEs under the new standard. Consolidation of these VIEs by Avista Corp. is not required because the Company does not have majority ownership in any of the entities, it does not have the power to direct any activities of the entities and it does not have the power to appoint executive leadership (including the board of directors). Avista Corp.'s total investment in these entities is not material and it does not have any additional commitments to these VIEs beyond the initial investment. See Note 3 for additional discussion of VIEs.

ASU No. 2016-02 "Leases (Topic 842)."

In February 2016, the FASB issued ASU No. 2016-02. This ASU introduces a new lessee model that requires most leases to be capitalized and shown on the balance sheet with corresponding lease assets and liabilities. The standard also aligns certain of the underlying principles of the new lessor model with those in Topic 606, the FASB's new revenue recognition standard. Furthermore, this ASU addresses other issues that arise under the current lease model; for example, eliminating the required use of bright-line tests in current GAAP for determining lease classification (operating leases versus capital leases). This ASU also includes enhanced disclosures surrounding leases. This ASU is effective for periods beginning on or after December 15, 2018; however, early adoption is permitted. Upon adoption, this ASU must be applied using a modified retrospective approach to the earliest period presented, which will likely require restatements of previously issued financial statements. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. The Company evaluated this standard and determined that it will most likely not early adopt this standard before its effective date in 2019. The Company has formed a lease standard implementation team that is working through the implementation process. The most significant implementation challenge identified thus far relates to identifying a complete population of leases and potential leases under the new lease standard. Also, the Company is monitoring utility industry implementation guidance as it relates to several unresolved issues to determine if there will be an industry consensus, including whether right-of-ways are considered leases. The Company cannot, at this time, estimate the potential impact on its future financial condition, results of operations and cash flows.

ASU No. 2016-09 "Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting."

In March 2016, the FASB issued ASU No. 2016-09. This ASU simplifies several aspects of the accounting for employee share-based payment transactions including:

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

This ASU is effective for periods beginning after December 15, 2016 and early adoption is permitted. The Company early adopted this standard during the second quarter of 2016, with a retrospective effective date of January 1, 2016. The adoption of this standard resulted in a recognized income tax benefit of $1.6 million in 2016 associated with excess tax benefits on settled share-based employee payments. In addition, the Consolidated Statement of Cash Flows for 2016 included the excess tax benefits as an operating activity rather than as a financing activity. Periods prior to 2016 were not restated for the adoption of this accounting standard as the Company has adopted this standard on a prospective basis beginning January 1, 2016.

NOTE 3. VARIABLE INTEREST ENTITIES

Lancaster Power Purchase Agreement

The Company has a PPA for the purchase of all the output of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in Kootenai County, Idaho, owned by an unrelated third-party (Rathdrum Power LLC), through 2026.

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026 and Avista Corp. does not have any further obligations after the expiration. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp.'s consolidated financial statements. The Company has a future contractual obligation of approximately $283.6 million under the PPA (representing the fixed capacity and operations and maintenance payments through 2026) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

Limited Partnerships and Similar Entities

The Company adopted ASU No. 2015-02 effective January 1, 2016. As a result of the adoption of this ASU, the Company evaluated all of its existing investments to determine if any entities would be considered VIEs under the new guidance and whether consolidation would be required. Under the ASU, a limited partnership or similar legal entity that is the functional equivalent of a limited partnership would be considered a VIE regardless of whether it otherwise qualifies as a voting interest entity unless a simple majority or lower threshold of the "unrelated" limited partners (i.e., parties other than the general partner, entities under common control with the general partner, and other parties acting on behalf of the general partner) have substantive kick-out rights (including liquidation rights) or participating rights.

The Company has six investments in limited partnerships (or the functional equivalent) where Avista Corp. is a limited partner investor in an investment fund where the general partner makes all of the investment and operating decisions with regards to the partnership and fund. To remove the general partner from any of the funds, approval from greater than a simple majority of the limited partners is required. As such, the limited partners do not have substantive kick-out rights and these investments are considered VIEs. Consolidation of these VIEs by Avista Corp. is not required because the Company does not have majority ownership in any of the funds, it does not have the power to direct any activities of the funds, and it does not have the power to appoint executive leadership, including the board of directors.

Avista Corp. participates in profits and losses of the investment funds based on its ownership percentage and its losses are capped at its total initial investment in the funds. For five of the six VIEs, Avista Corp. does not have any additional commitments beyond its initial investment. For the sixth VIE, Avista Corp. has up to a $25.0 million total commitment, and as of December 31, 2016, has invested $2.1 million, leaving $22.9 million remaining to be invested. In addition, the Company is not allowed to withdraw any capital contributions from the investment funds until after the funds' expiration dates and all liabilities of the funds are settled. The expiration dates range from 2017 to 2032, with one investment having no termination date (as it is perpetual). As of December 31, 2016, the Company has a total carrying amount in these investment funds of $7.0 million.

NOTE 4. BUSINESS ACQUISITIONS

Alaska Energy and Resources Company

On July 1, 2014, the Company acquired AERC, based in Juneau, Alaska, and as of that date, AERC became a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is AEL&P, a regulated utility which provides electric services to approximately 17,000 customers in Juneau, Alaska. In addition to the regulated utility, AERC owns AJT Mining, which is an inactive mining company holding certain properties.

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

In connection with the closing, Avista Corp. issued 4,501,441 new shares of common stock to the shareholders of AERC based on a contractual formula that resulted in a price of $32.46 per share, reflecting a purchase price of $170.0 million, plus acquired cash, less outstanding debt and other closing adjustments. Avista Corp. also paid $4.8 million in cash. The total fair value of all consideration transferred was $154.9 million and resulted in goodwill of $52.4 million, which is not deductible for tax purposes.

The fair value of assets acquired and liabilities assumed as of July 1, 2014 (after consideration of a working capital adjustment and income tax true-ups during the second quarter of 2015) were as follows (in thousands):

	July 1, 2014
Assets acquired:	
Current Assets:	
Cash	$ 19,704
Accounts receivable - gross totals $3,928	3,851
Materials and supplies	2,017
Other current assets	999
Total current assets	26,571
Utility Property:	
Utility plant in service	113,964
Utility property under long-term capital lease	71,007
Construction work in progress	3,440
Total utility property	188,411
Other Non-current Assets:	
Non-utility property	6,660
Electric plant held for future use	3,711
Goodwill (1)	52,426
Other deferred charges and non-current assets	5,368
Total other non-current assets	68,165
Total assets	$ 283,147
Liabilities Assumed:	
Current Liabilities:	
Accounts payable	$ 700
Current portion of long-term debt and capital lease obligations	3,773
Other current liabilities (1)	2,807
Total current liabilities	7,280
Long-term debt	37,227
Capital lease obligations	68,840
Other non-current liabilities and deferred credits (1)	14,889
Total liabilities	$ 128,236
Total net assets acquired	$ 154,911

(1) During the second quarter of 2015, the Company recorded a reduction to goodwill of approximately $0.3 million due to income tax related adjustments.

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

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

	2016	2015	2014
Actual Avista Corp. revenues from continuing operations (excluding AERC)	$ 1,395,989	$ 1,439,807	$ 1,450,918
Supplemental pro forma AERC revenues (1)	46,494	44,969	46,467
Total pro forma revenues	1,442,483	1,484,776	1,497,385
Actual AERC revenues included in Avista Corp. revenues (1)	46,494	44,969	21,644
Actual Avista Corp. net income from continuing operations attributable to Avista Corp. shareholders (excluding AERC)	129,505	111,772	116,665
Actual Avista Corp. net income from discontinued operations attributable to Avista Corp. shareholders	—	5,147	72,224
Adjustment to Avista Corp.'s net income for acquisition costs (net of tax) (2)	—	22	870
Supplemental pro forma AERC net income (1)	7,723	6,308	8,806
Total pro forma net income	137,228	123,249	198,565
Actual AERC net income included in Avista Corp. net income (1)	$ 7,723	$ 6,308	$ 3,152

(1) AERC was acquired on July 1, 2014; therefore, all the revenues and net income for the second half of 2014 through 2016 are actual amounts that are included in Avista Corp.'s overall results. All revenue and net income amounts prior to July 1, 2014 are supplemental pro forma amounts and are excluded from Avista Corp.'s overall results.

(2) This adjustment is to treat all transaction costs as if they occurred on January 1, 2013 and to remove them from the periods in which they actually occurred. The transaction costs were expensed and presented in the Consolidated Statements of Income in other operating expenses within utility operating expenses. Since the start of the transaction through December 31, 2016, Avista Corp. has expensed $3.0 million (pre-tax) in total transaction fees. In addition to the amounts expensed, through December 31, 2016, Avista Corp. has included $0.4 million in fees associated with the issuance of common stock for the transaction as a reduction to common stock. These fees do not impact the supplemental pro forma information above.

NOTE 5. DISCONTINUED OPERATIONS

On June 30, 2014, Avista Capital, completed the sale of its interest in Ecova to Cofely USA Inc., an unrelated party to Avista Corp. The sales price was $335.0 million in cash, less the payment of debt and other customary closing adjustments. At the closing of the transaction on June 30, 2014, Ecova became a wholly-owned subsidiary of Cofely USA Inc. and the Company has not had and will not have any further involvement with Ecova after such date.

The purchase price of $335.0 million, as adjusted, was divided among all the security holders of Ecova pro rata based on ownership. After consideration of all escrow amounts received, the sales transaction provided cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.7 million, and resulted in a net gain of $74.8 million. Almost all of the net gain was recognized in 2014 with some true-ups during 2015.

Prior to the completion of the sales transaction, Ecova was a reportable business segment. The following table presents amounts that were included in discontinued operations for the years ended December 31, 2015 and 2014 (dollars in thousands):

	2015	2014
Revenues	$ —	$ 87,534
Gain on sale of Ecova (1)	777	160,612
Transaction expenses and accelerated employee benefits (2)	71	9,062
Gain on sale of Ecova, net of transaction expenses	706	151,550
Income before income taxes	706	156,025
Income tax expense (benefit) (3)	(4,441)	83,614
Net income from discontinued operations	5,147	72,411
Net income attributable to noncontrolling interests	—	(187)
Net income from discontinued operations attributable to Avista Corp. shareholders	$ 5,147	$ 72,224

(1) This represents the gross gain recorded to discontinued operations. The total gain net of taxes and transactions expenses was $74.8 million, of which $69.7 million was recognized during 2014.

(2) Avista Corp.'s portion of the total transaction expenses was $9.1 million (including amounts which were withheld from the transaction net proceeds). All transaction expenses paid on the Ecova sale (including Avista Corp.'s portion and the portion attributable to the minority interest holders of Ecova) were $11.1 million, of which $5.5 million was withheld from the net proceeds and the remainder was paid during 2014. The transaction expenses were for legal, accounting and other consulting fees, and the accelerated employee benefits related to employee stock options which were settled in accordance with the Ecova equity plan.

(3) The tax benefit during 2015 primarily resulted from the reversal of a valuation allowance against net operating losses at Ecova because the net operating losses were deemed realizable after further evaluation.

NOTE 6. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Utilities is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Utilities utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these commodity price exposures. The Company has an energy resources risk policy and control procedures to manage these risks.

As part of the Company's resource procurement and management operations in the electric business, the Company engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve the Company's load obligations and the use of these resources to capture available economic value. The Company transacts in wholesale markets by selling and purchasing electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging the related financial risks. These transactions range from terms of intra-hour up to multiple years.

As part of its resource procurement and management of its natural gas business, the Company makes continuing projections of its natural gas loads and assesses available natural gas resources including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to the Company's distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, the Company plans and executes a series of transactions to hedge a portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as four natural gas operating years (November through October) into the future. Avista Corp. also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

The Company is required to plan for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event. The Company generally has more pipeline and storage capacity than what is needed during periods other than a peak day. The Company optimizes its natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Avista Utilities also optimizes its natural gas storage capacity by purchasing and storing natural gas when prices are traditionally lower, typically in the summer, and withdrawing during higher priced months, typically during the winter. However, if market conditions and prices indicate that the Company should buy or sell natural gas during other times in the year, the Company engages in optimization transactions to capture value in the marketplace. Natural gas optimization activities include, but are not limited to, wholesale market sales of surplus natural gas supplies, purchases and sales of natural gas to optimize use of pipeline and storage capacity, and participation in the transportation capacity release market.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2016 that are expected to be settled in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2017	510	907	15,475	110,380	316	1,552	4,165	73,110
2018	397	—	—	52,755	286	1,244	1,360	15,113
2019	235	—	610	29,475	158	982	1,345	4,020
2020	—	—	910	2,725	—	—	1,430	—
2021	—	—	—	—	—	—	1,060	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents the underlying energy commodity derivative volumes as of December 31, 2015 that were expected to be settled in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2016	407	1,954	17,252	142,693	280	2,656	3,182	112,233
2017	397	97	675	49,200	255	483	1,360	26,965
2018	397	—	—	15,118	286	—	1,360	2,738
2019	235	—	305	6,935	158	—	1,345	—
2020	—	—	455	905	—	—	1,430	—
Thereafter	—	—	—	—	—	—	1,060	—

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

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

Foreign Currency Exchange Derivatives

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

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

	2016	2015
Number of contracts	21	24
Notional amount (in United States dollars)	$ 2,819	$ 1,463
Notional amount (in Canadian dollars)	3,754	2,002

Interest Rate Swap Derivatives

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. The Company hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swap derivatives and U.S. Treasury lock agreements. These interest rate swap derivatives and U.S. Treasury lock agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the unsettled interest rate swap derivatives that the Company has outstanding as of the balance sheet date indicated below (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2016	6	75,000	2017
	14	275,000	2018
	6	70,000	2019
	2	20,000	2020
	5	60,000	2022
December 31, 2015	6	115,000	2016
	3	45,000	2017
	11	245,000	2018
	2	30,000	2019
	1	20,000	2022

During the third quarter 2016, in connection with the execution of a purchase agreement for bonds that the Company issued in December 2016, the Company cash-settled seven interest rate swap derivatives (notional aggregate amount of $125.0 million) and paid a total of $54.0 million. The interest rate swap derivatives were settled in connection with the pricing of $175.0 million of Avista Corp. first mortgage bonds that were issued in December 2016 (see Note 14). Upon settlement of interest rate swap derivatives, the cash payments made or received are recorded as a regulatory asset or liability and are subsequently amortized as a component of interest expense over the life of the associated debt. The settled interest rate swap derivatives are also included as a part of the Company's cost of debt calculation for ratemaking purposes.

The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swaps outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. The Company would be required to make cash payments to settle the interest rate swap derivatives if the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, the Company receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Consolidated Balance Sheet as of December 31, 2016 and December 31, 2015 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheet as of December 31, 2016 (in thousands):

Derivative and Balance Sheet Location	Fair Value Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet
Foreign currency exchange derivatives				
Other current liabilities	$ 5	$ (28)	$ —	$ (23)
Interest rate swap derivatives				
Other current assets	3,393	—	—	3,393
Other property and investments-net and other non-current assets	5,754	(397)	—	5,357
Other current liabilities	—	(15,756)	9,731	(6,025)
Non-current interest rate swap derivative liabilities	3,951	(57,825)	25,169	(28,705)
Energy commodity derivatives				
Other current assets	18,682	(16,787)	—	1,895
Current energy commodity derivative liabilities	16,335	(29,598)	6,228	(7,035)
Other non-current liabilities, regulatory liabilities and deferred credits	13,071	(29,990)	3,630	(13,289)
Total derivative instruments recorded on the balance sheet	$ 61,191	$ (150,381)	$ 44,758	$ (44,432)

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

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

Exposure to Demands for Collateral

The Company's derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement, in the event of a downgrade in the Company's credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. The Company actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

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

	2016	2015
Energy commodity derivatives		
Cash collateral posted	$ 17,134	$ 28,716
Letters of credit outstanding	24,400	28,200
Balance sheet offsetting (cash collateral against net derivative positions)	9,858	14,526
Interest rate swap derivatives		
Cash collateral posted	34,900	34,030
Letters of credit outstanding	3,600	9,600
Balance sheet offsetting (cash collateral against net derivative positions)	34,900	34,030

Certain of the Company's derivative instruments contain provisions that require the Company to maintain an "investment grade" credit rating from the major credit rating agencies. If the Company's credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions.

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

	2016	2015
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 1,124	$ 7,090
Additional collateral to post	1,046	6,980
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	73,978	85,498
Additional collateral to post	21,100	18,750

NOTE 7. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, Colstrip, located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income. The Company's share of utility plant in service for Colstrip and accumulated depreciation (inclusive of the ARO assets and accumulated amortization) were as follows as of December 31 (dollars in thousands):

	2016	2015
Utility plant in service	$ 380,406	$ 362,199
Accumulated depreciation	(249,359)	(243,363)

See Note 9 for further discussion of AROs.

NOTE 8. PROPERTY, PLANT AND EQUIPMENT

The balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in thousands):

	2016	2015
Avista Utilities:		
Electric production	$ 1,346,332	$ 1,217,179
Electric transmission	682,529	640,586
Electric distribution	1,525,175	1,468,157
Electric construction work-in-progress (CWIP) and other	296,912	358,846
Electric total	3,850,948	3,684,768
Natural gas underground storage	44,672	43,080
Natural gas distribution	954,298	878,982
Natural gas CWIP and other	57,601	62,024
Natural gas total	1,056,571	984,086
Common plant (including CWIP)	527,458	456,796
Total Avista Utilities	5,434,977	5,125,650
AEL&P:		
Electric production	94,839	72,292
Electric transmission	20,252	18,817
Electric distribution	20,057	19,005
Electric production held under long-term capital lease	71,007	71,007
Electric CWIP and other	7,190	16,971
Electric total	213,345	198,092
Common plant	8,651	8,133
Total AEL&P	221,996	206,225
Other (1)	30,764	25,709
Total	$ 5,687,737	$ 5,357,584

(1) Included in other property and investments-net and other non-current assets on the Consolidated Balance Sheets. Accumulated depreciation was $11.2 million as of December 31, 2016 and $10.6 million as of December 31, 2015 for the other businesses.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

The Company has recorded liabilities for future AROs to:

- restore coal ash containment ponds at Colstrip,
- cap a landfill at the Kettle Falls Plant,
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease, and
- dispose of PCBs in certain transformers.

Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for the:

- removal and disposal of certain transmission and distribution assets, and
- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

On April 17, 2015, the EPA published a final rule regarding coal combustion residuals (CCR), also termed coal combustion byproducts or coal ash, in the Federal Register, and this rule became effective on October 15, 2015. Colstrip, of which Avista Corp. is a 15 percent owner of units 3 & 4, produces this byproduct. The rule established technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. The Company, in conjunction with the other Colstrip owners, developed a multi-year compliance plan to strategically address the CCR requirements and existing state obligations while maintaining operational stability. During 2015, the operator of Colstrip provided an initial cost estimate of the expected retirement costs associated with complying with the new CCR rule. Based on the initial assessments, Avista Corp. recorded an increase to its ARO of $12.5 million during 2015 with a corresponding increase in the cost basis of the utility plant. During 2016, due to additional information and updated estimates, the ARO increased to $13.6 million (including accretion of $0.7 million).

The actual asset retirement costs related to the CCR rule requirements may vary substantially from the estimates used to record the increased ARO due to uncertainty about the compliance strategies that will be used and the preliminary 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. Avista Corp. will coordinate with the plant operator and continue to gather additional data in future periods to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, Avista Corp. will update the ARO for these changes in estimates, which could be material. The Company expects to seek recovery of any increased costs related to complying with the new rule through customer rates.

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

	2016	2015	2014
Asset retirement obligation at beginning of year	$ 15,997	$ 3,028	$ 2,859
Liabilities incurred	430	12,539	—
Liabilities settled	(1,529)	(29)	(41)
Accretion expense	617	459	210
Asset retirement obligation at end of year	$ 15,515	$ 15,997	$ 3,028

NOTE 10. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Utilities. AEL&P (not discussed below) participates in a defined contribution multiemployer plan for its union workers and a defined contribution money purchase pension plan for its nonunion workers. METALfx (not discussed below) has a defined contribution 401(k) savings plan. None of the subsidiary retirement plans, individually or in the aggregate, are significant to Avista Corp.

Avista Utilities

The Company has a defined benefit pension plan covering the majority of all regular full-time employees at Avista Utilities that were hired prior to January 1, 2014. Individual benefits under this plan are based upon the employee's years of service, date of hire and average compensation as specified in the plan. Non-union employees hired on or after January 1, 2014 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $12.0 million in cash to the pension plan in 2016, $12.0 million in 2015 and $32.0 million in 2014. The Company expects to contribute $22.0 million in cash to the pension plan in 2017.

The Company also has a SERP that provides additional pension benefits to executive officers and certain key employees of the Company. The SERP is intended to provide benefits to individuals whose benefits under the defined benefit pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. The liability and expense for this plan are included as pension benefits in the tables included in this Note.

The Company expects that benefit payments under the pension plan and the SERP will total (dollars in thousands):

	2017	2018	2019	2020	2021	Total 2022-2026
Expected benefit payments	$ 30,971	$ 32,014	$ 33,047	$ 34,545	$ 35,892	$ 196,322

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits.

The Company provides certain health care and life insurance benefits for eligible retired employees that were hired prior to January 1, 2014. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The liability and expense of this plan are included as other postretirement benefits. Non-union employees hired on or after January 1, 2014, will have access to the retiree medical plan upon retirement; however, Avista Corp. will no longer provide a contribution toward their medical premium.

The Company has a Health Reimbursement Arrangement (HRA) to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on the employee's years of service and the ending salary. The liability and expense of the HRA are included as other postretirement benefits.

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. Under the plan, an executive officer's designated beneficiary will receive a payment equal to twice the executive officer's annual base salary at the time of death (or if death occurs after retirement, a payment equal to twice the executive officer's total annual pension benefit). The liability and expense for this plan are included as other postretirement benefits.

The Company expects that benefit payments under other postretirement benefit plans will total (dollars in thousands):

	2017	2018	2019	2020	2021	Total 2022-2026
Expected benefit payments	$ 6,991	$ 7,302	$ 7,580	$ 6,479	$ 6,675	$ 34,704

The Company expects to contribute $7.0 million to other postretirement benefit plans in 2017, representing expected benefit payments to be paid during the year excluding the Medicare Part D subsidy. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2016 and 2015 and the components of net periodic benefit costs for the years ended December 31, 2016, 2015 and 2014 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2016	2015	2016	2015
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 613,503	$ 634,674	$ 138,795	$ 127,989
Service cost	18,302	19,791	3,205	2,925
Interest cost	27,544	26,117	6,110	5,158
Actuarial (gain)/loss	39,997	(35,790)	(3,648)	12,668
Plan change	—	(228)	—	(1,000)
Cumulative adjustment to reclassify liability	—	—	(1,042)	(1,521)
Benefits paid	(32,874)	(31,061)	(6,967)	(7,424)
Benefit obligation as of end of year	$ 666,472	$ 613,503	$ 136,453	$ 138,795
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 517,234	$ 539,311	$ 30,868	$ 31,312
Actual return on plan assets	43,212	(4,305)	2,497	(444)
Employer contributions	12,000	12,000	—	—
Benefits paid	(31,532)	(29,772)	—	—
Fair value of plan assets as of end of year	$ 540,914	$ 517,234	$ 33,365	$ 30,868
Funded status	$ (125,558)	$ (96,269)	$ (103,088)	$ (107,927)
Unrecognized net actuarial loss	178,783	162,961	81,979	92,433
Unrecognized prior service cost	23	25	(8,981)	(10,180)
Prepaid (accrued) benefit cost	53,248	66,717	(30,090)	(25,674)
Additional liability	(178,806)	(162,986)	(72,998)	(82,253)
Accrued benefit liability	$ (125,558)	$ (96,269)	$ (103,088)	$ (107,927)
Accumulated pension benefit obligation	$ 583,498	$ 542,209	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 60,670	$ 65,652
For fully eligible employees			$ 34,429	$ 34,498
For other participants			$ 41,354	$ 38,645

	Pension Benefits		Other Post-retirement Benefits	
	2016	2015	2016	2015
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 15	$ 16	$ (5,854)	$ (6,617)
Unrecognized net actuarial loss	116,209	105,925	53,303	60,081
Total	116,224	105,941	47,449	53,464
Less regulatory asset	(108,903)	(99,414)	(47,202)	(53,341)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 7,321	$ 6,527	$ 247	$ 123

	Pension Benefits		Other Post-retirement Benefits	
	2016	2015	2016	2015
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	4.26%	4.57%	4.23%	4.57%
Discount rate for annual expense	4.57%	4.21%	4.57%	4.16%
Expected long-term return on plan assets	5.40%	5.30%	6.03%	6.36%
Rate of compensation increase	4.78%	4.87%		
Medical cost trend pre-age 65 – initial			7.00%	7.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2023	2022
Medical cost trend post-age 65 – initial			7.00%	7.00%
Medical cost trend post-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2024	2023

	Pension Benefits			Other Post-retirement Benefits		
	2016	2015	2014	2016	2015	2014
Components of net periodic benefit cost:						
Service cost	$ 18,302	$ 19,791	$ 15,757	$ 3,205	$ 2,925	$ 1,844
Interest cost	27,544	26,117	26,224	6,110	5,158	5,226
Expected return on plan assets	(27,547)	(28,299)	(32,131)	(1,861)	(1,991)	(1,903)
Amortization of prior service cost	2	2	22	(1,208)	(1,199)	(1,116)
Net loss recognition	8,511	9,451	4,731	5,728	5,095	4,289
Net periodic benefit cost	$ 26,812	$ 27,062	$ 14,603	$ 11,974	$ 9,988	$ 8,340

Plan Assets

The Finance Committee of the Company's Board of Directors approves investment policies, objectives and strategies that seek an appropriate return for the pension plan and other postretirement benefit plans and reviews and approves changes to the investment and funding policies.

The Company has contracted with investment consultants who are responsible for managing/monitoring the individual investment managers. The investment managers' performance and related individual fund performance is periodically reviewed by an internal benefits committee and by the Finance Committee to monitor compliance with investment policy objectives and strategies.

Pension plan assets are invested in mutual funds, trusts and partnerships that hold marketable debt and equity securities, real estate, absolute return and commodity funds. In seeking to obtain the desired return to fund the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes and also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range. The target investment allocation percentages by asset classes are indicated in the table below:

	2016	2015
Equity securities	37%	27%
Debt securities	45%	58%
Real estate	8%	6%
Absolute return	10%	9%

The 2016 target investment allocation percentages were revised in the fourth quarter of 2016 and the pension plan assets were subsequently reinvested during the fourth quarter of 2016 and first quarter of 2017 to move toward the new target investment allocation percentages. The target asset allocation percentages were modified to better align the asset allocations with the funded status of the pension plan. Future contributions to the plan will also be increased to improve the funded status of the plan.

The fair value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the reported last sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, the investment manager estimates fair value based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). Investments in common/collective trust funds are presented at estimated fair value, which is determined based on the unit value of the fund. Unit value is determined by an independent trustee, which sponsors the fund, by dividing the fund's net assets by its units outstanding at the valuation date. The Company's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. The fair values of the closely held investments and partnership interests are based upon the allocated share of the fair value of the underlying assets as well as the allocated share of the undistributed profits and losses, including realized and unrealized gains and losses. Most of the Company's investments in closely held investments and partnership interests have redemption limitations that range from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days. One investment in a partnership has a lock-up for redemption currently expiring in 2022 and is subject to extension.

The fair value of pension plan assets invested in real estate was determined by the investment manager based on three basic approaches:

- properties are externally appraised on an annual basis by independent appraisers, additional appraisals may be performed as warranted by specific asset or market conditions,
- property valuations are reviewed quarterly and adjusted as necessary, and
- loans are reflected at fair value.

The fair value of pension plan assets was determined as of December 31, 2016 and 2015.

Pension plan other postretirement plan assets whose fair values are measured using net asset value (NAV) are excluded from the fair value hierarchy and are included as reconciling items in the tables below.

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2016 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 10,179	$ —	$ 10,179
Fixed income securities:				
U.S. government issues	—	30,919	—	30,919
Corporate issues	—	193,563	—	193,563
International issues	—	34,145	—	34,145
Municipal issues	—	18,888	—	18,888
Mutual funds:				
U.S. equity securities	120,856	—	—	120,856
International equity securities	30,025	—	—	30,025
Absolute return (1)	6,622	—	—	6,622
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	19,779
International equity securities	—	—	—	29,140
Partnership/closely held investments:				
Absolute return (1)	—	—	—	39,077
Private equity funds (2)	—	—	—	72
Real estate	—	—	—	7,649
Total	$ 157,503	$ 287,694	$ —	$ 540,914

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2015 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 86	$ 10,641	$ —	$ 10,727
Fixed income securities:				
U.S. government issues	—	47,845	—	47,845
Corporate issues	—	187,308	—	187,308
International issues	—	34,458	—	34,458
Municipal issues	—	22,416	—	22,416
Mutual funds:				
U.S. equity securities	87,678	—	—	87,678
International equity securities	40,343	—	—	40,343
Absolute return (1)	13,996	—	—	13,996
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	24,147
Partnership/closely held investments:				
Absolute return (1)	—	—	—	38,302
Private equity funds (2)	—	—	—	73
Real estate	—	—	—	9,941
Total	$ 142,103	$ 302,668	$ —	$ 517,234

(1) This category invests in multiple strategies to diversify risk and reduce volatility. The strategies include: (a) event driven, relative value, convertible, and fixed income arbitrage, (b) distressed investments, (c) long/short equity and fixed income, and (d) market neutral strategies.
(2) This category includes private equity funds that invest primarily in U.S. companies.

The fair value of other postretirement plan assets invested in debt and equity securities was based primarily on market prices. The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2016 and 2015.

The fair value of other postretirement plan assets was determined as of December 31, 2016 and 2015.

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2016 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 6	$ —	$ 6
Mutual funds:				
Balanced index fund (1)	33,359	—	—	33,359
Total	$ 33,359	$ 6	$ —	$ 33,365

(1) The balanced index fund is a single mutual fund that includes a percentage of U.S. equity securities, fixed income securities and International securities.

The following table discloses by level within the fair value hierarchy (see Note 16 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2015 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 9	$ —	$ 9
Mutual funds:				
Fixed income securities	12,000	—	—	12,000
U.S. equity securities	13,224	—	—	13,224
International equity securities	5,635	—	—	5,635
Total	$ 30,859	$ 9	$ —	$ 30,868

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 2016 by $8.6 million and the service and interest cost by $1.0 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2016 by $6.7 million and the service and interest cost by $0.7 million.

401(k) Plans and Executive Deferral Plan

Avista Utilities and METALfx have salary deferral 401(k) plans that are defined contribution plans and cover substantially all employees. Employees can make contributions to their respective accounts in the plans on a pre-tax basis up to the maximum amount permitted by law. The respective company matches a portion of the salary deferred by each participant according to the schedule in the respective plan.

Employer matching contributions were as follows for the years ended December 31 (dollars in thousands):

	2016	2015	2014
Employer 401(k) matching contributions	$ 8,710	$ 8,011	$ 6,862

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust.

There were deferred compensation assets included in other property and investments-net and corresponding deferred compensation liabilities included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2016	2015
Deferred compensation assets and liabilities	$ 7,679	$ 8,093

NOTE 11. ACCOUNTING FOR INCOME TAXES

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

	2016	2015	2014
Current income tax expense (benefit)	$ (46,457)	$ 12,212	$ (67,059)
Deferred income tax expense	124,543	55,237	139,299
Total income tax expense	$ 78,086	$ 67,449	$ 72,240

State income taxes do not represent a significant portion of total income tax expense on the Consolidated Statements of Income for any periods presented.

A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2016, 2015 and 2014) applied to income before income taxes as set forth in the accompanying Consolidated Statements of Income is as follows for the years ended December 31 (dollars in thousands):

	2016		2015		2014	
Federal income taxes at statutory rates	$ 75,391	35.0 %	$ 64,967	35.0 %	$ 67,237	35.0 %
Increase (decrease) in tax resulting from:						
Tax effect of regulatory treatment of utility plant differences	3,297	1.5	4,358	2.3	4,008	2.1
State income tax expense	1,316	0.6	1,012	0.5	506	0.2
Settlement of prior year tax returns and adjustment of tax reserves	13	—	(992)	(0.5)	1,104	0.6
Manufacturing deduction	—	—	(1,198)	(0.6)	(169)	(0.1)
Settlement of equity awards	(1,597)	(0.7)	—	—	—	—
Other	(334)	(0.1)	(698)	(0.4)	(446)	(0.2)
Total income tax expense	$ 78,086	36.3 %	$ 67,449	36.3 %	$ 72,240	37.6 %

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards. The total net deferred income tax liability consisted of the following as of December 31 (dollars in thousands):

	2016	2015
Deferred income tax assets:		
Unfunded benefit obligation	$ 80,230	$ 75,716
Derivatives	31,872	47,009
Regulatory deferred tax credits	15,192	—
Tax credits	27,931	15,011
Power and natural gas deferrals	19,415	12,866
Deferred compensation	11,141	10,354
Other	29,512	29,471
Total gross deferred income tax assets	215,293	190,427
Valuation allowances for deferred tax assets	(7,946)	(2,862)
Total deferred income tax assets after valuation allowances	207,347	187,565
Deferred income tax liabilities:		
Differences between book and tax basis of utility plant	812,916	723,661
Regulatory asset on utility, property plant and equipment	37,301	36,917
Regulatory asset for pensions and other postretirement benefits	84,040	82,253
Utility energy commodity derivatives	31,871	47,010
Long-term debt and borrowing costs	31,955	14,027
Settlement with Coeur d'Alene Tribe	11,711	12,084
Other regulatory assets	30,183	11,691
Other	8,298	7,399
Total deferred income tax liabilities	1,048,275	935,042
Net long-term deferred income tax liability	$ 840,928	$ 747,477

The realization of deferred income tax assets is dependent upon the ability to generate taxable income in future periods. The Company evaluated available evidence supporting the realization of its deferred income tax assets and determined it is more likely than not that deferred income tax assets will be realized.

As of December 31, 2016, the Company had $17.1 million of state tax credit carryforwards of which it is expected $7.9 million may expire unused; the Company has reflected the net amount of $9.2 million as an asset at December 31, 2016. State tax credits expire from 2019 to 2028.

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon and Montana. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2011 and all issues were resolved related to these years. The statute of limitations for the IRS to review the 2012 tax year has expired, leaving the 2013 through 2015 tax years still open for review. The Company believes that any open tax years for federal or state income taxes will not result in adjustments that would be significant to the consolidated financial statements.

The Company had net regulatory assets related to the probable recovery of certain deferred income tax liabilities from customers through future rates as of December 31 (dollars in thousands):

	2016	2015
Regulatory assets for deferred income taxes	$ 109,853	$ 101,240
Regulatory liabilities for deferred income taxes	28,966	17,609

NOTE 12. ENERGY PURCHASE CONTRACTS

The below discussion only relates to Avista Utilities. The sole energy purchase contract at AEL&P is a PPA for the Snettisham hydroelectric project and it is accounted for as a capital lease. AEL&P does not have any other significant operating agreements or contractual obligations. See Note 14 for further discussion of the Snettisham PPA.

Avista Utilities has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The remaining term of the contracts range from one month to twenty-five years.

Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs, which are included in utility resource costs in the Consolidated Statements of Income, were as follows for the years ended December 31 (dollars in thousands):

	2016	2015	2014
Utility power resources	$ 402,575	$ 511,937	$ 556,915

The following table details Avista Utilities' future contractual commitments for power resources (including transmission contracts) and natural gas resources (including transportation contracts) (dollars in thousands):

	2017	2018	2019	2020	2021	Thereafter	Total
Power resources	$ 202,494	$ 187,080	$ 174,285	$ 109,878	$ 96,485	$ 775,548	$ 1,545,770
Natural gas resources	95,549	65,230	53,860	41,340	29,306	349,468	634,753
Total	$ 298,043	$ 252,310	$ 228,145	$ 151,218	$ 125,791	$ 1,125,016	$ 2,180,523

These energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail electric and natural gas customers' energy requirements, including contracts entered into for resource optimization. As a result, these costs are recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost deferral and recovery mechanisms.

The above future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with certain PUDs to purchase portions of the output of certain generating facilities. Although Avista Utilities has no investment in the PUD generating facilities, the fixed contracts obligate Avista Utilities to pay certain minimum amounts whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Consolidated Statements of Income. The contractual amounts included above consist of Avista Utilities' share of existing debt service cost and its proportionate share of the variable operating expenses of these projects. The minimum amounts payable under these contracts are based in part on the proportionate share of the debt service requirements of the PUD's revenue bonds for which the Company is indirectly responsible. The Company's total future debt service obligation associated with the revenue bonds outstanding at December 31, 2016 (principal and interest) was $65.2 million.

In addition, Avista Utilities has operating agreements, settlements and other contractual obligations related to its generating facilities and transmission and distribution services. The expenses associated with these agreements are reflected as other operating expenses in the Consolidated Statements of Income. The following table details future contractual commitments under these agreements (dollars in thousands):

	2017	2018	2019	2020	2021	Thereafter	Total
Contractual obligations	$ 33,922	$ 28,783	$ 32,549	$ 32,160	$ 27,019	$ 189,000	$ 343,433

NOTE 13. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. A two-year option was exercised by the Company in 2016 to extend the maturity of the facility agreement to April 2021.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2016, the Company was in compliance with this covenant.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company's revolving committed lines of credit were as follows as of December 31 (dollars in thousands):

	2016	2015
Balance outstanding at end of period	$ 120,000	$ 105,000
Letters of credit outstanding at end of period	$ 34,353	$ 44,595
Average interest rate at end of period	1.50%	1.18%

As of December 31, 2016 and 2015, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Consolidated Balance Sheet.

AEL&P

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

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," including the impact of the Snettisham bonds to be greater than 67.5 percent at any time. As of December 31, 2016, AEL&P was in compliance with this covenant.

NOTE 14. LONG-TERM DEBT AND CAPITAL LEASES

The following details long-term debt outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2016	2015
Avista Corp. Secured Long-Term Debt				
2016	First Mortgage Bonds (1)	0.84%	$ —	$ 90,000
2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (2)	(2)	66,700	66,700
2034	Secured Pollution Control Bonds (2)	(2)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds	4.11%	60,000	60,000
2045	First Mortgage Bonds	4.37%	100,000	100,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
2051	First Mortgage Bonds (3)	3.54%	175,000	—
	Total Avista Corp. secured long-term debt		1,621,700	1,536,700
Alaska Electric Light and Power Company Secured Long-Term Debt				
2044	First Mortgage Bonds	4.54%	75,000	75,000
	Total secured long-term debt		1,696,700	1,611,700
Alaska Energy and Resources Company Unsecured Long-Term Debt				
2019	Unsecured Term Loan	3.85%	15,000	15,000
	Total secured and unsecured long-term debt		1,711,700	1,626,700
Other Long-Term Debt Components				
	Capital lease obligations		65,435	68,601
	Settled interest rate swap derivatives (4)		—	(26,515)
	Unamortized debt discount		(792)	(956)
	Unamortized long-term debt issuance costs		(10,639)	(10,852)
	Total		1,765,704	1,656,978
	Secured Pollution Control Bonds held by Avista Corporation (2)		(83,700)	(83,700)
	Current portion of long-term debt and capital leases		(3,287)	(93,167)
	Total long-term debt and capital leases		$ 1,678,717	$ 1,480,111

(1) In August 2016, Avista Corp. entered into a term loan agreement with a commercial bank in the amount of $70.0 million with a maturity date of December 30, 2016. Loans under this agreement were unsecured and had a variable annual interest rate. The Company borrowed the entire $70.0 million available under this agreement, which was used to repay a portion of the $90.0 million in first mortgage bonds that matured in August 2016. This term loan was subsequently repaid in full in December using the proceeds from the first mortgage bonds issued in December 2016 (discussed below).

(2) In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheets.

(3) In December 2016, Avista Corp. issued and sold $175.0 million of 3.54 percent first mortgage bonds due in 2051 pursuant to a bond purchase agreement with institutional investors in the private placement market. The total net proceeds from the sale of the bonds were used to repay the $70.0 million term loan discussed above and to repay a portion of the borrowings outstanding under the Company's $400.0 million committed line of credit. In connection with the execution of the bond purchase agreement, the Company cash-settled seven interest rate swap derivatives (notional aggregate amount of $125.0 million) and paid a total of $54.0 million.

(4) Prior to December 31, 2016, settled interest rate swap derivatives were included as part of long-term debt on the Consolidated Balance Sheets because they were considered similar to a debt discount or premium. During 2016, the Company reevaluated the presentation of settled interest rate swap derivatives and determined that since they are regulatory assets and liabilities that are being recovered through the ratemaking process, the more appropriate classification is as regulatory assets and liabilities rather than as a component of long-term debt. As such, as of December 31, 2016, the Company has included unamortized settled interest rate swap derivatives of $91.9 million in regulatory assets and $12.4 million in regulatory liabilities. The Company did not reclassify any amounts as of December 31, 2015 and prior because the amounts are not material to the financial statements. The increase in settled interest rate swap derivatives during 2016 is due to the cash settlement of interest rate swap derivatives discussed in detail above. There is no impact to the Consolidated Statements of Income and the Consolidated Statements of Cash Flows for any periods as a result of the balance sheet reclassification.

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

	2017	2018	2019	2020	2021	Thereafter	Total
Debt maturities	$ —	$ 272,500	$ 105,000	$ 52,000	$ —	$ 1,250,047	$ 1,679,547

Substantially all of Avista Utilities' and AEL&P's owned properties are subject to the lien of their respective mortgage indentures. Under the Mortgages and Deeds of Trust (Mortgages) securing their first mortgage bonds (including secured medium-term notes), Avista Utilities and AEL&P may each issue additional first mortgage bonds under their specific mortgage in an aggregate principal amount equal to the sum of:

- 66-2/3 percent of the cost or fair value (whichever is lower) of property additions of that entity which have not previously been made the basis of any application under that entity's Mortgage, or
- an equal principal amount of retired first mortgage bonds of that entity which have not previously been made the basis of any application under that entity's Mortgage, or
- deposit of cash.

However, Avista Utilities and AEL&P may not individually issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the particular entity issuing the bonds has "net earnings" (as defined in that entity's Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months that were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the first mortgage bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2016, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.2 billion in aggregate principal amount of additional first mortgage bonds at Avista Utilities and $20.8 million at AEL&P.

Snettisham Capital Lease Obligation

Included in long-term capital leases above is a power purchase agreement between AEL&P and AIDEA, an agency of the State of Alaska, under which AEL&P has a take-or-pay obligation, expiring in December 2038, to purchase all the output of the 78 MW Snettisham Hydroelectric Project. For accounting purposes, this power purchase agreement is treated as a capital lease.

The balances related to the Snettisham capital lease obligation as of December 31 were as follows (dollars in thousands):

	2016	2015
Capital lease obligation (1)	$ 62,160	$ 64,455
Capital lease asset (2)	71,007	71,007
Accumulated amortization of capital lease asset (2)	9,104	5,462

(1) The capital lease obligation amount is equal to the amount of AIDEA's revenue bonds outstanding.
(2) These amounts are included in utility plant in service on the Consolidated Balance Sheets.

Interest on the capital lease obligation and amortization of the capital lease asset are included in utility resource costs in the Consolidated Statements of Income and totaled the following amounts for the years ended December 31 (dollars in thousands):

	2016	2015
Interest on capital lease obligation	$ 3,157	$ 3,587
Amortization of capital lease asset	3,642	3,641

AIDEA issued $100.0 million of revenue bonds in 1998 to finance its acquisition of the project and the payments by AEL&P were designed to be sufficient to enable the AIDEA to pay the principal of and interest on its revenue bonds, which bore interest at rates ranging from 4.9 percent to 6.0 percent and were set to mature in January 2034.

In August 2015, AIDEA issued $65.7 million of new revenue bonds for the purpose of refunding all of the remaining outstanding revenue bonds for the Snettisham Hydroelectric Project. The new revenue bonds have interest rates ranging from 4.0 percent to 5.0 percent and mature in January 2034. The capital lease obligation on Avista Corp.'s Consolidated Balance Sheet at any given time is equal to the amount of revenue bonds outstanding at that time. AEL&P is scheduled to make its last capital lease payment to AIDEA in December 2033. The payments by AEL&P under the PPA between AEL&P and AIDEA are unconditional, notwithstanding any suspension, reduction or curtailment of the operation of the project. The bonds are payable solely out of AIDEA's receipts under the power purchase agreement. AEL&P is also obligated to operate, maintain and insure the project. The PPA did not change as a result of the refunding, other than lower capital lease payments, and the lower capital lease payments that resulted from the refunding will be passed through to AEL&P's customers. AEL&P's payments for power under the agreement are between $10.0 million and $10.5 million per year, including the capital lease principal and interest of approximately $5.5 million per year.

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

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

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

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

	2017	2018	2019	2020	2021	Thereafter	Total
Principal	$ 2,415	$ 2,535	$ 2,660	$ 2,800	$ 2,935	$ 48,815	$ 62,160
Interest	3,042	2,921	2,795	2,662	2,522	16,674	30,616
Total	$ 5,457	$ 5,456	$ 5,455	$ 5,462	$ 5,457	$ 65,489	$ 92,776

NOTE 15. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly.

The distribution rates paid were as follows during the years ended December 31:

	2016	2015	2014
Low distribution rate	1.29%	1.11%	1.10%
High distribution rate	1.81%	1.29%	1.11%
Distribution rate at the end of the year	1.81%	1.29%	1.11%

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II at any time and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed. The Company does not include these capital trusts in its consolidated financial statements as Avista Corp. is not the primary beneficiary. As such, the sole assets of the capital trusts are $51.5 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Consolidated Balance Sheets. Interest expense to affiliated trusts in the Consolidated Statements of Income represents interest expense on these debentures.

NOTE 16. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion and material capital leases) and long-term debt to affiliated trusts are reported at carrying value on the Consolidated Balance Sheets.

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

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

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

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

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

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

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

	2016		2015	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,048,661	$ 951,000	$ 1,055,797
Long-term debt (Level 3)	677,000	675,251	592,000	595,018
Snettisham capital lease obligation (Level 3)	62,160	62,800	64,455	63,150
Long-term debt to affiliated trusts (Level 3)	51,547	38,660	51,547	36,083

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 75.00 to 122.59, where a par value of 100.00 represents the carrying value recorded on the Consolidated Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates using comparable debt with similar risk and terms if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds. Due to the unique nature of the Snettisham capital lease obligation, the estimated fair value of these items was determined based on a discounted cash flow model using available market information. Prior to December 31, 2016, the Snettisham capital lease obligation was discounted to present value using the Moody's Aaa Corporate discount rate as published by the Federal Reserve. This rate was discontinued during the fourth quarter of 2016, as such going forward, the Company is using the Morgan Markets A Ex-Fin discount rate, which is the closest approximation to the rate previously used.

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

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2016					
Assets:					
Energy commodity derivatives	$ —	$ 47,994	$ —	$ (46,099)	$ 1,895
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	69	(69)	—
Power exchange agreement	—	—	25	(25)	—
Foreign currency exchange derivatives	—	5	—	(5)	—
Interest rate swap derivatives	—	13,098	—	(4,348)	8,750
Deferred compensation assets:					
Fixed income securities (2)	1,789	—	—	—	1,789
Equity securities (2)	5,481	—	—	—	5,481
Total	$ 7,270	$ 61,097	$ 94	$ (50,546)	$ 17,915
Liabilities:					
Energy commodity derivatives	$ —	$ 56,871	$ —	$ (55,957)	$ 914
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	5,954	(69)	5,885
Power exchange agreement	—	—	13,474	(25)	13,449
Power option agreement	—	—	76	—	76
Interest rate swap derivatives	—	73,978	—	(39,248)	34,730
Foreign currency exchange derivatives	—	28	—	(5)	23
Total	$ —	$ 130,877	$ 19,504	$ (95,304)	$ 55,077

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

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists. In addition, the Company nets derivative assets and derivative liabilities against any payables and receivables for cash collateral held or placed with these same counterparties.

(2) These assets are trading securities and are included in other property and investments-net and other non-current assets on the Consolidated Balance Sheets.

The difference between the amount of derivative assets and liabilities disclosed in respective levels in the table above and the amount of derivative assets and liabilities disclosed on the Consolidated Balance Sheets is due to netting arrangements with certain counterparties. See Note 6 for additional discussion of derivative netting.

To establish fair value for energy commodity derivatives, the Company uses quoted market prices and forward price curves to estimate the fair value of utility derivative commodity instruments included in Level 2. In particular, electric derivative valuations are performed using market quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using market quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

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

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

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.4 million as of December 31, 2016 and $0.6 million as of December 31, 2015.

Level 3 Fair Value

Under the power exchange agreement the Company purchases power at a price that is based on the average operating and maintenance (O&M) charges from three surrogate nuclear power plants around the country. To estimate the fair value of this agreement the Company estimates the difference between the purchase price based on the future O&M charges and forward prices for energy. The Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average O&M charges from the three surrogate nuclear power plants for the current year. Because the nuclear power plant O&M charges are only known for one year, all forward years are estimated assuming an annual escalation. In addition to the forward price being estimated using unobservable inputs, the Company also estimates the volumes of the transactions that will take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, a change in the current year O&M charges for the surrogate plants is accompanied by a directionally similar change in O&M charges in future years. There is generally not a correlation between external market prices and the O&M charges used to develop the internal forward price.

For the power commodity option agreement, the Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include: 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges), 2) estimated delivery volumes, and 3) volatility rates. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices and volatility rates are accompanied by directionally similar changes in the strike price and volatility assumptions used in the calculation.

For the natural gas commodity exchange agreement, the Company uses the same Level 2 brokered quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions have not been highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2016 (dollars in thousands):

	Fair Value (Net) at December 31, 2016	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (13,449)	Surrogate facility pricing	O&M charges	$33.59-$49.15/MWh (1)
			Escalation factor	3% - 2017 to 2019
			Transaction volumes	241,558 - 396,984 MWhs
Power option agreement	(76)	Black-Scholes-Merton	Strike price	$37.83/MWh - 2019
				$54.40/MWh - 2018
			Delivery volumes	157,517 - 285,979 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	(5,885)	Internally derived weighted-average cost of gas	Forward purchase prices	$1.83 - $3.06/mmBTU
			Forward sales prices	$1.90 - $5.14/mmBTU
			Purchase volumes	115,000 - 310,000 mmBTUs
			Sales volumes	60,000 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2016 were $39.22 per MWh. For ratemaking purposes the average O&M charges to be included for recovery in retail rates vary slightly between regulatory jurisdictions. The average O&M charges for the delivery year beginning in 2016 were $44.33 for Washington and $39.22 for Idaho.
(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.35 for 2017 to 0.26 in December 2018.

The valuation methods, significant inputs and resulting fair values described above were developed by the Company's management and are reviewed on at least a quarterly basis to ensure they provide a reasonable estimate of fair value each reporting period.

The following table presents activity for energy commodity derivative assets (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the years ended December 31 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Year ended December 31, 2016:				
Balance as of January 1, 2016	$ (5,039)	$ (21,961)	$ (124)	$ (27,124)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	259	400	48	707
Settlements	(1,105)	8,112	—	7,007
Ending balance as of December 31, 2016 (2)	$ (5,885)	$ (13,449)	$ (76)	$ (19,410)
Year ended December 31, 2015:				
Balance as of January 1, 2015	$ (35)	$ (23,299)	$ (424)	$ (23,758)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	(6,008)	(6,198)	300	(11,906)
Settlements	1,004	7,536	—	8,540
Ending balance as of December 31, 2015 (2)	$ (5,039)	$ (21,961)	$ (124)	$ (27,124)
Year ended December 31, 2014:				
Balance as of January 1, 2014	$ (1,219)	$ (14,441)	$ (775)	$ (16,435)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	3,873	(10,002)	351	(5,778)
Settlements	(2,689)	1,144	—	(1,545)
Ending balance as of December 31, 2014 (2)	$ (35)	$ (23,299)	$ (424)	$ (23,758)

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

NOTE 17. COMMON STOCK

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

- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements,
- the hydroelectric licensing requirements of section 10(d) of the FPA (see Note 1), and
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Utilities to maintain a capital structure of no less than 40 percent common equity (inclusive of short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC.

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

	2016	2015	2014
Dividends paid per common share	$ 1.37	$ 1.32	$ 1.27

Under the most restrictive of the dividend limitations discussed above, which are the requirements of the OPUC approval of the AERC acquisition, the amount available for dividends at December 31, 2016 was limited to $263.4 million.

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2016 and 2015.

Stock Repurchase Programs

During 2014 and 2015, Avista Corp.'s Board of Directors approved programs to repurchase shares of the Company's outstanding common stock. The number of shares repurchased and the total cost of repurchases are disclosed in the Consolidated Statements of Equity and Redeemable Noncontrolling Interests. The average repurchase price was $31.57 in 2014 and $32.66 in 2015. All repurchased shares reverted to the status of authorized but unissued shares.

Equity Issuances

In March 2016, the Company entered into four separate sales agency agreements under which Avista Corp.'s sales agents may offer and sell up to 3.8 million new shares of Avista Corp.'s common stock, no par value, from time to time. The sales agency agreements expire on February 29, 2020. In 2016, 1.6 million shares were issued under these agreements resulting in total net proceeds of $65.3 million, leaving 2.2 million shares remaining to be issued.

In 2016, the Company also issued $1.7 million (net of issuance costs) of common stock under the employee plans.

NOTE 18. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORPORATION SHAREHOLDERS

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

	2016	2015	2014
Numerator:			
Net income from continuing operations attributable to Avista Corp. shareholders	$ 137,228	$ 118,080	$ 119,817
Net income from discontinued operations attributable to Avista Corp. shareholders	—	5,147	72,224
Subsidiary earnings adjustment for dilutive securities (discontinued operations)	—	—	5
Adjusted net income from discontinued operations attributable to Avista Corp. shareholders for computation of diluted earnings per common share	$ —	$ 5,147	$ 72,229
Denominator:			
Weighted-average number of common shares outstanding-basic	63,508	62,301	61,632
Effect of dilutive securities:			
Performance and restricted stock awards	412	407	255
Weighted-average number of common shares outstanding-diluted	63,920	62,708	61,887
Earnings per common share attributable to Avista Corp. shareholders, basic:			
Earnings per common share from continuing operations	$ 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	$ 2.16	$ 1.98	$ 3.12
Earnings per common share attributable to Avista Corp. shareholders, diluted:			
Earnings per common share from continuing operations	$ 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	$ 2.15	$ 1.97	$ 3.10

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

NOTE 19. COMMITMENTS AND CONTINGENCIES

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

California Refund Proceeding

In February 2016, APX, a market maker in the California Refund Proceedings in whose markets Avista Energy participated in the summer of 2000, asserted that Avista Energy and its other customer/participants may be responsible for a share of the disgorgement penalty APX may be found to owe to Pacific Gas & Electric (PG&E), Southern California Edison, San Diego Gas & Electric, the California Attorney General (AG), the California Department of Water Resources (CERS), and the California Public Utilities Commission (together, the "California Parties"). The penalty arises as a result of the FERC's finding that APX committed violations in the California market in the summer of 2000. APX is making these assertions despite Avista Energy having been dismissed in FERC Opinion No. 536 from the on-going administrative proceeding at the FERC regarding potential wrongdoing in the California markets in the summer of 2000. APX has identified Avista Energy's share of APX's exposure to be as much as $16.0 million even though no wrongdoing allegations are specifically attributable to Avista Energy. Avista Energy believes its settlement with the California Parties in 2014 insulates it from any such liability and that as a dismissed party it cannot be drawn back into the litigation. Avista Energy intends to vigorously dispute APX's assertions of indirect liability, but cannot at this time predict the eventual outcome.

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC had failed to take into account new evidence of market manipulation and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the new evidence. The Ninth Circuit expressly declined to direct the FERC to grant refunds. On October 3, 2011, the FERC issued an Order on Remand and on April 5, 2013 expanded the temporal scope of the proceeding to permit parties to submit evidence on transactions during the period from January 1, 2000 through and including June 20, 2001.

On July 11, 2012 and March 28, 2013, Avista Energy and Avista Corp. filed settlements of all issues in this docket with regard to the claims made by the City of Tacoma and the California AG (on behalf of the California Department of Water Resources). The FERC approved the settlements and they are final.

The remaining direct claimant against Avista Corp. and Avista Energy in this proceeding was the City of Seattle, Washington (Seattle). An evidentiary, trial type hearing before an Administrative Law Judge (ALJ) to permit parties to present evidence of unlawful market activity was conducted in 2013.

With regard to the Seattle claims, on March 28, 2014, the Presiding ALJ issued an Initial Decision finding that: 1) Seattle failed to demonstrate that either Avista Corp. or Avista Energy engaged in unlawful market activity and also failed to identify any specific contracts at issue; 2) Seattle failed to demonstrate that contracts with either Avista Corp. or Avista Energy imposed an excessive burden on consumers or seriously harmed the public interest; and that 3) Seattle failed to demonstrate that either Avista Corp. or Avista Energy engaged in any specific violations of substantive provisions of the FPA or any filed tariffs or rate schedules. Accordingly, the ALJ denied all of Seattle's claims under both section 206 and section 309 of the FPA. On May 22, 2015, the FERC issued its Order on Initial Decision in which it upheld the ALJ's Initial Decision denying all of Seattle's claims against Avista Corp. and Avista Energy. Seattle filed a Request for Rehearing of the FERC's Order on Initial Decision which was denied on December 31, 2015. Seattle appealed the FERC's decision to the Ninth Circuit. In October 2016, Seattle settled all of the matters with the remaining parties and withdrew its appeal at the Ninth Circuit. All the remaining parties signed the settlement agreement and a petition to dismiss the case was filed with the Ninth Circuit on October 27, 2016. There are no remaining claims outstanding under this proceeding. The settlement did not have a material adverse effect on the Company's financial condition, results of operations or cash flows.

Sierra Club and Montana Environmental Information Center Litigation

In 2013, the Sierra Club and Montana Environmental Information Center (MEIC) (collectively "Plaintiffs"), filed a Complaint in the United States District Court for the District of Montana, Billings Division, against the Owners of the Colstrip Generating Project ("Colstrip"); Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The other Colstrip co-Owners are Talen Montana, LLC (formerly PPL Montana, LLC, an indirect subsidiary of Talen Energy Corporation), Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Complaint alleged certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements with respect to post-January 1, 2001 Colstrip projects. The Plaintiffs requested that the Court grant injunctive and declaratory relief, order remediation of alleged environmental damages, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs' costs of litigation and attorney fees.

The liability trial was scheduled to start on May 31, 2016. The parties engaged in settlement discussions with the Plaintiffs to resolve the claims raised in the litigation. On July 12, 2016, the parties filed a proposed Consent Decree with the court which contained the terms of the settlement of the matter with respect to all four units at Colstrip. The settlement does not include any monetary payments by any party, dismisses all claims against all four units, and provides for the shut-down of units 1 & 2 (which are owned solely by Talen Montana, LLC and Puget Sound Energy) no later than July, 2022. The Consent Decree was entered on September 6, 2016. The parties have petitioned the Court for costs and attorneys' fees. The Court denied the defendant's claim for fees and reduced the plaintiff's claimed fees from approximately \$3.0 million to \$1.6 million. On February 15, 2017 the Court issued an Order adopting this resolution in full and closing the case.

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

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels (referred to as "Total Dissolved Gas" or "TDG") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of Cabinet Gorge particularly during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement (CFSA) as incorporated in Avista Corp.'s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. Under the terms of a gas supersaturation mitigation plan, Avista is reducing TDG by constructing spill crest modifications on spill gates at the dam, and the Company expects to continue spill crest modifications over the next several years, in ongoing consultation with key stakeholders. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the United States Fish and Wildlife Service (USFWS) listed bull trout as threatened under the Endangered Species Act. In 2010, the USFWS issued a revised designation of critical habitat for bull trout, which includes the lower Clark Fork River. The USFWS issued a final recovery plan in October 2015.

The CFSA describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. Parties to the CFSA are working to resolve several issues. The Company believes its ongoing efforts through the CFSA continue to effectively address issues related to bull trout. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Collective Bargaining Agreements

The Company's collective bargaining agreements with the IBEW represent approximately 45 percent of all of Avista Utilities' employees. A new three-year agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the Avista Utilities' bargaining unit employees was approved in March 2016 and expires in March 2019.

A three-year agreement in Oregon, which covers approximately 50 employees was set to expire in March 2017. A new three-year agreement has been approved by the IBEW membership that will expire in March 2020. It is still awaiting approval from the National IBEW.

A collective bargaining agreement with the local union of the IBEW in Alaska expires in March 2017. The collective bargaining agreement with the IBEW in Alaska represents approximately 50 percent of all AERC employees. The remainder of AERC's employees are non-union.

There is a risk that if collective bargaining agreements expire and new agreements are not reached in each of our jurisdictions, employees could strike. Given the magnitude of employees that are covered by collective bargaining agreements, this could result in disruptions of our operations. However, the Company believes that the possibility of this occurring is remote.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company’s estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

The Company routinely assesses, based on studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who either have or have not agreed to a settlement as well as recoveries from insurance carriers. The Company’s policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred. For matters that affect Avista Utilities’ or AEL&P's operations, the Company seeks, to the extent appropriate, recovery of incurred costs through the ratemaking process.

The Company has potential liabilities under the Endangered Species Act for species of fish, plants and wildlife that have either already been added to the endangered species list, listed as “threatened” or petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company. However, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to these issues.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. In addition, the company holds additional non-hydro water rights. The state of Montana is examining the status of all water right claims within state boundaries through a general adjudication. Claims within the Clark Fork River basin could adversely affect the energy production of the Company’s Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated adjudication in northern Idaho, which will ultimately include the lower Clark Fork River, the Spokane River and the Coeur d’Alene basin. The Company is and will continue to be a participant in these and any other relevant adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

NOTE 20. REGULATORY MATTERS

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities as of December 31, 2016 (dollars in thousands):

		Receiving Regulatory Treatment				
	Remaining Amortization Period	(1) Earning A Return	Not Earning A Return	(2) Expected Recovery or Refund	Total 2016	Total 2015
Regulatory Assets:						
Investment in exchange power-net	2019	$ 6,533	$ —	$ —	$ 6,533	$ 8,983
Regulatory assets for deferred income tax	(3)	101,372	8,481	—	109,853	101,240
Regulatory assets for pensions and other postretirement benefit plans	(4)	—	240,114	—	240,114	235,009
Current regulatory asset for energy commodity derivatives	(5)	—	11,365	—	11,365	17,260
Unamortized debt repurchase costs	(6)	13,700	—	—	13,700	15,520
Regulatory asset for settlement with Coeur d'Alene Tribe	2059	45,265	—	—	45,265	46,576
Demand side management programs	(3)	—	15,700	—	15,700	3,168
Deferred maintenance costs	2018	—	2,672	—	2,672	4,823
Decoupling surcharge	2018	43,126	—	—	43,126	13,312
Regulatory asset for utility plant to be abandoned	(7)	19,100	—	—	19,100	—
Regulatory asset for interest rate swaps	(8)	37,912	—	123,596	161,508	83,973
Non-current regulatory asset for energy commodity derivatives	(5)	—	16,919	—	16,919	32,420
Other regulatory assets	(3)	3,633	5,755	4,585	13,973	17,348
Total regulatory assets		$ 270,641	$ 301,006	$ 128,181	$ 699,828	$ 579,632
Regulatory Liabilities:						
Natural gas deferrals	(3)	$ 30,820	$ —	$ —	$ 30,820	$ 17,880
Power deferrals	(3)	23,528	—	—	23,528	18,747
Regulatory liability for utility plant retirement costs	(9)	273,983	—	—	273,983	261,594
Income tax related liabilities	(3)	—	28,966	—	28,966	17,609
Regulatory liability for interest rate swaps	(8)	12,442	—	8,749	21,191	23
Provision for earnings sharing rebate	(3)	—	3,697	6,600	10,297	12,237
Decoupling rebate	2017	2,405	—	—	2,405	2,373
Other regulatory liabilities	(3)	2,505	3,257	—	5,762	3,420
Total regulatory liabilities		$ 345,683	$ 35,920	$ 15,349	$ 396,952	$ 333,883

(1) Earning a return includes either interest on the regulatory asset/liability or a return on the investment as a component of rate base at the allowed rate of return.

(2) Expected recovery is pending regulatory treatment including regulatory assets and liabilities with prior regulatory precedence.

(3) Remaining amortization period varies depending on timing of underlying transactions.

(4) As the Company has historically recovered and currently recovers its pension and other postretirement benefit costs related to its regulated operations in retail rates, the Company records a regulatory asset for that portion of its pension and other postretirement benefit funding deficiency.

(5) The UTC and the IPUC issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.

(6) For the Company’s Washington jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. In the Company’s other regulatory jurisdictions, premiums paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. These costs are included in the Company's cost of debt calculation for ratemaking purposes and are recovered through retail rates.

(7) In March 2016, the UTC granted the Company's Petition for an Accounting Order to defer and include in a regulatory asset the undepreciated value of its existing Washington electric meters for the opportunity for later recovery. This accounting treatment is related to the Company's plan to replace approximately 253,000 of its existing electric meters with new two-way digital meters and the related software and support services through its AMI project in Washington State. Replacement of the meters is expected to begin in the second half of 2017. For ratemaking purposes, the existing electric meters won't be recorded as regulatory assets until they are physically removed from service, but for GAAP purposes, they are regulatory assets upon the commitment by management to retire the meters.

(8) For interest rate swap derivatives, each period Avista Utilities records all mark-to-market gains and losses in each accounting period as assets and liabilities and records offsetting regulatory assets and liabilities, such that there is no income statement impact. 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 and are also included as a part of the Company's cost of debt calculation for ratemaking purposes. See Note 14 regarding a reclassification of settled interest rate swap derivatives during 2016. Settled interest rate swap derivatives which have been through a general rate case proceeding are classified as earning a return in the table above, whereas all unsettled interest rate swap derivatives and settled interest rate swap derivatives which have not been included in a general rate case are classified as expected recovery.

(9) This amount is dependent upon the cost of removal of underlying utility plant assets and the life of utility plant.

Power Cost Deferrals and Recovery Mechanisms

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

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

In Washington, the ERM allows Avista Utilities to periodically increase or decrease electric rates with UTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. The Washington ERM calculation is subject to certain deadbands and sharing bands. For 2016, the Company recognized a pre-tax benefit of $5.1 million under the ERM in Washington compared to a benefit of $6.3 million for 2015. Total net deferred power costs under the ERM were a liability of $21.3 million as of December 31, 2016 compared to a liability of $18.0 million as of December 31, 2015, and these deferred power cost balances represent amounts due to customers.

Avista Utilities has a PCA mechanism in Idaho that allows it to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, Avista Utilities defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. The October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $2.2 million as of December 31, 2016 compared to an asset of $0.2 million as of December 31, 2015.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Utilities files a PGA in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. Total net deferred natural gas costs to be refunded to customers were a liability of $30.8 million as of December 31, 2016 compared to a liability of $17.9 million as of December 31, 2015.

Decoupling and Earnings Sharing Mechanisms

Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Utilities' jurisdictions, each month Avista Utilities' electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes, rather than KWh and therm sales. The difference between revenues based on the number of customers and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year.

Washington Decoupling and Earnings Sharing

In Washington, the UTC approved the Company's decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to 3 percent on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

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

Idaho Fixed Cost Adjustment (FCA) and Earnings Sharing Mechanisms

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

For the period 2013 through 2015 the Company had an after-the-fact earnings test, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earned more than a 9.8 percent ROE, the Company was required to share with customers 50 percent of any earnings above the 9.8 percent. There was no provision for a surcharge to customers if the Company's ROE was less than 9.8 percent. This after-the-fact earnings test was discontinued as part of the settlement of the Company's 2015 Idaho electric and natural gas general rates cases. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Oregon Decoupling Mechanism

In February 2016, the OPUC approved the implementation of a decoupling mechanism for natural gas, similar to the Washington and Idaho mechanisms described above. The decoupling mechanism became effective on March 1, 2016 and there will be an opportunity for interested parties to review the mechanism and recommend changes, if any, by September 2019. An earnings review is conducted on an annual basis, which is filed by the Company with the OPUC on or before June 1 of each year for the prior calendar year. In the annual earnings review, if the Company earns more than 100 basis points above its allowed return on equity, one-third of the earnings above the 100 basis points would be deferred and later returned to customers. The earnings review is separate from the decoupling mechanism and was in place prior to decoupling. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

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

	December 31, 2016	December 31, 2015
Washington		
Decoupling surcharge	$ 30,408	$ 10,933
Provision for earnings sharing rebate	(5,113)	(3,422)
Idaho		
Decoupling surcharge	$ 8,292	n/a
Provision for earnings sharing rebate	(5,184)	(8,814)
Oregon		
Decoupling surcharge	$ 2,021	n/a
Provision for earnings sharing rebate	—	—

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

NOTE 21. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss) attributable to Avista Corp. shareholders. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation; therefore, it is considered one segment. AEL&P is a separate reportable business segment as it has separate financial reports that are reviewed in detail by the Chief Operating Decision Maker and its operations and risks are sufficiently different from Avista Utilities and the other businesses at AERC that it cannot be aggregated with any other operating segments. The Other category, which is not a reportable segment, includes other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital.

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

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the year ended December 31, 2016:						
Operating revenues	$ 1,372,638	$ 46,276	$ 1,418,914	$ 23,569	$ —	$ 1,442,483
Resource costs	539,352	12,014	551,366	—	—	551,366
Other operating expenses	304,644	11,151	315,795	25,501	—	341,296
Depreciation and amortization	155,162	5,352	160,514	769	—	161,283
Income (loss) from operations	277,070	15,434	292,504	(2,701)	—	289,803
Interest expense (2)	83,070	3,584	86,654	608	(132)	87,130
Income taxes	74,121	5,321	79,442	(1,356)	—	78,086
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	132,490	7,968	140,458	(3,230)	—	137,228
Capital expenditures (3)	390,690	15,954	406,644	353	—	406,997

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the year ended December 31, 2015:						
Operating revenues	$ 1,411,863	$ 44,778	$ 1,456,641	$ 28,685	$ (550)	$ 1,484,776
Resource costs	644,991	11,973	656,964	—	—	656,964
Other operating expenses	292,096	11,125	303,221	30,076	(550)	332,747
Depreciation and amortization	138,236	5,263	143,499	695	—	144,194
Income (loss) from operations	241,228	14,072	255,300	(2,086)	—	253,214
Interest expense (2)	76,405	3,558	79,963	610	(132)	80,441
Income taxes	64,489	4,202	68,691	(1,242)	—	67,449
Net income (loss) from continuing operations attributable to Avista Corp. shareholders	113,360	6,641	120,001	(1,921)	—	118,080
Capital expenditures (3)	381,174	12,251	393,425	885	—	394,310
For the year ended December 31, 2014:						
Operating revenues	$ 1,413,499	$ 21,644	$ 1,435,143	$ 39,219	$ (1,800)	$ 1,472,562
Resource costs	672,344	5,900	678,244	—	—	678,244
Other operating expenses	280,964	5,868	286,832	32,218	(1,800)	317,250
Depreciation and amortization	126,987	2,583	129,570	610	—	130,180
Income from operations	239,976	6,221	246,197	6,391	—	252,588
Interest expense (2)	73,750	1,382	75,132	1,004	(384)	75,752
Income taxes	67,634	1,816	69,450	2,790	—	72,240
Net income from continuing operations attributable to Avista Corp. shareholders	113,263	3,152	116,415	3,236	166	119,817
Capital expenditures (3)	323,931	1,585	325,516	406	—	325,922
Total Assets:						
As of December 31, 2016	$ 4,975,555	$ 273,770	$ 5,249,325	$ 60,430	$ —	$ 5,309,755
As of December 31, 2015	$ 4,601,708	$ 265,735	$ 4,867,443	$ 39,206	$ —	$ 4,906,649
As of December 31, 2014	$ 4,357,760	$ 263,070	$ 4,620,830	$ 80,141	$ —	$ 4,700,971

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

(2) Including interest expense to affiliated trusts.

(3) The capital expenditures for the other businesses are included as other capital expenditures on the Consolidated Statements of Cash Flows. The remainder of the balance included in other capital expenditures on the Consolidated Statements of Cash Flows for 2014 are related to Ecova.

NOTE 22. SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

The Company's energy operations are significantly affected by weather conditions. Consequently, there can be large variances in revenues, expenses and net income between quarters based on seasonal factors such as, but not limited to, temperatures and streamflow conditions.

A summary of quarterly operations (in thousands, except per share amounts) for 2016 and 2015 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2016				
Operating revenues	$ 418,173	$ 318,838	$ 303,349	$ 402,123
Operating expenses	312,088	257,247	263,755	319,590
Income from operations	$ 106,085	$ 61,591	$ 39,594	$ 82,533
Net income (1)	57,665	27,287	12,261	40,103
Net income attributable to noncontrolling interests	(16)	(33)	(27)	(12)
Net income attributable to Avista Corporation shareholders (1)	$ 57,649	$ 27,254	$ 12,234	$ 40,091
Outstanding common stock:				
weighted-average, basic	62,605	63,386	63,857	64,185
weighted-average, diluted	62,907	63,783	64,325	64,620
Earnings per common share attributable to Avista Corp. shareholders, diluted (1)	$ 0.92	$ 0.43	$ 0.19	$ 0.62

	Three Months Ended			
	March 31	June 30	September 30	December 31
2015				
Operating revenues from continuing operations	$ 446,490	$ 337,332	$ 313,649	$ 387,305
Operating expenses from continuing operations	356,915	279,972	277,737	316,938
Income from continuing operations	$ 89,575	$ 57,360	$ 35,912	$ 70,367
Net income from continuing operations	$ 46,462	$ 25,078	$ 12,754	$ 33,876
Net income from discontinued operations	—	196	289	4,662
Net income	46,462	25,274	13,043	38,538
Net income attributable to noncontrolling interests	(13)	(28)	(32)	(17)
Net income attributable to Avista Corporation shareholders	$ 46,449	$ 25,246	$ 13,011	$ 38,521
Amounts attributable to Avista Corp. shareholders:				
Net income from continuing operations attributable to Avista Corp. shareholders	$ 46,449	$ 25,050	$ 12,722	$ 33,859
Net income from discontinued operations attributable to Avista Corp. shareholders	—	196	289	4,662
Net income attributable to Avista Corp. shareholders	$ 46,449	$ 25,246	$ 13,011	$ 38,521
Outstanding common stock:				
weighted-average, basic	62,318	62,281	62,299	62,308
weighted-average, diluted	62,889	62,600	62,688	62,758
Earnings per common share attributable to Avista Corp. shareholders, diluted:				
Earnings per common share from continuing operations	$ 0.74	$ 0.40	$ 0.21	$ 0.54
Earnings per common share from discontinued operations	—	—	—	0.07
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$ 0.74	$ 0.40	$ 0.21	$ 0.61

(1) The Company adopted ASU 2016-09 during the second quarter of 2016, with a retrospective effective date of January 1, 2016. The adoption of this standard resulted in a recognized income tax benefit of $1.6 million in 2016 associated with excess tax benefits on settled share-based employee payments. Because this standard was adopted in the second quarter of 2016, but has a retrospective effective date of January 1, 2016, the effects from the adoption were pushed back to the first quarter of 2016 and the results for that quarter were recast in the presentation above. In all future reports which include the first quarter of 2016, the results for that quarter will be recast to include the effects of the excess tax benefits recognized.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Act) that are designed to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company’s management, including its principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. With the participation of the Company’s principal executive officer and principal financial officer, the Company's management evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon this evaluation, the Company’s principal executive officer and principal financial officer have concluded that the Company’s disclosure controls and procedures are effective at a reasonable assurance level as of December 31, 2016.

Management’s Report on Internal Control Over Financial Reporting

The Company’s management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). The Company’s internal control over financial reporting is a process designed under the supervision of the Company’s principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company’s financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America.

The Company’s internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company’s assets that could have a material effect on the Company’s financial statements.

Under the supervision and with the participation of the Company’s management, including the Company’s principal executive officer and principal financial officer, the Company conducted an assessment of the effectiveness of the Company’s internal control over financial reporting based on the framework established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that the Company’s internal control over financial reporting as of December 31, 2016 is effective at a reasonable assurance level.

The Company’s independent registered public accounting firm, Deloitte & Touche LLP, has issued an attestation report on the Company’s internal control over financial reporting as of December 31, 2016.

Changes in Internal Control Over Financial Reporting

There have been no changes in the Company’s internal control over financial reporting that occurred during the Company’s last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company’s internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Avista Corporation and subsidiaries (the “Company”) as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management’s Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016 of the Company and our report dated February 21, 2017 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 21, 2017

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

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

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 11, 2017, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2016, relating to its Annual Meeting of Shareholders held on May 12, 2016.

Executive Officers of the Registrant

Name	Age	Business Experience
Scott L. Morris	59	Chairman, President and Chief Executive Officer effective January 1, 2008. Director since February 9, 2007; President and Chief Operating Officer May 2006 – December 2007; Senior Vice President February 2002 – May 2006; Vice President November 2000 – February 2002; President – Avista Utilities August 2000 – December 2008; General Manager – Avista Utilities for the Oregon and California operations October 1991 – August 2000; various other management and staff positions with the Company since 1981.
Mark T. Thies	53	Treasurer since January 2013; Senior Vice President and Chief Financial Officer (Principal Financial Officer) since September 2008; prior to employment with the Company held the following positions with Black Hills Corporation: Executive Vice President and Chief Financial Officer March 2003 to January 2008; Senior Vice President and Chief Financial Officer March 2000 to March 2003; Controller May 1997 to March 2000.
Marian M. Durkin	63	Senior Vice President, General Counsel and Chief Compliance Officer since November 2005; Corporate Secretary since May 2016; Senior Vice President and General Counsel August 2005 – November 2005; prior to employment with the Company: held several legal positions with United Air Lines, Inc. from 1995 to August 2005, most recently served as Vice President Deputy General Counsel and Assistant Secretary.
Karen S. Feltes	61	Senior Vice President of Human Resources since November 2005; Corporate Secretary November 2005 – April 2016; Vice President of Human Resources and Corporate Secretary March 2003 – November 2005; Vice President of Human Resources and Corporate Services February 2002 – March 2003; various human resources positions with the Company April 1998 – February 2002.
Dennis P. Vermillion	55	Senior Vice President since January 2010; Vice President July 2007- December 2009; President – Avista Utilities since January 2009; Vice President of Energy Resources and Optimization – Avista Utilities July 2007 – December 2008; President and Chief Operating Officer of Avista Energy February 2001 – July 2007; various other management and staff positions with the Company since 1985.
Jason R. Thackston	47	Senior Vice President since January 2014; Vice President of Energy Resources since December 2012; Vice President of Customer Solutions – Avista Utilities June 2012 - December 2012; Vice President of Energy Delivery April 2011 – December 2012; Vice President of Finance June 2009 – April 2011; various other management and staff positions with the Company since 1996.
Ryan L. Krasselt	47	Vice President, Controller and Principal Accounting Officer since October 2015; various other management and staff positions with the Company since 2001.
Kevin J. Christie	49	Vice President of Customer Solutions since February 2015; various other management and staff positions with the Company since 2005.
James M. Kensok	58	Vice President and Chief Information Officer since January 2007; Chief Information Officer February 2001 – December 2006; various other management and staff positions with the Company since 1996.
David J. Meyer	63	Vice President and Chief Counsel for Regulatory and Governmental Affairs since February 2004; Senior Vice President and General Counsel September 1998 – February 2004.

Executive Officers of the Registrant

Name	Age	Business Experience
Kelly O. Norwood	58	Vice President since November 2000; Vice President of State and Federal Regulation – Avista Utilities since March 2002; Vice President and General Manager of Energy Resources - Avista Utilities August 2000 – March 2002; various other management and staff positions with the Company since 1981.
Heather L. Rosentrater	39	Vice President of Energy Delivery since December 2015; various other management and staff positions with the Company since 1996.
Edward D. Schlect Jr.	56	Vice President and Chief Strategy Officer since September 2015; prior to employment with the Company, Executive Vice President of Corporate Development at Ecova, Inc.

All of the Company's executive officers, with the exception of James M. Kensok, David J. Meyer, Kelly O. Norwood, Kevin J. Christie and Heather L. Rosentrater were officers or directors of one or more of the Company's subsidiaries in 2016. The Company's executive officers are elected annually by the Board of Directors.

The Company has adopted a Code of Conduct for directors, officers (including the principal executive officer, principal financial officer and principal accounting officer), and employees. The Code of Conduct is available on the Company's website at www.avistacorp.com and will also be provided to any shareholder without charge upon written request to:

Avista Corp.
General Counsel
P.O. Box 3727 MSC-12
Spokane, Washington 99220-3727

Any changes to or waivers for executive officers and directors of the Company's Code of Conduct will be posted on the Company's website.

Item 11. Executive Compensation

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

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 11, 2017, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2016, relating to its Annual Meeting of Shareholders held on May 12, 2016.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

(a) Security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities):

Information regarding security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities) has been omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 11, 2017, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2016, relating to its Annual Meeting of Shareholders held on May 12, 2016; reference also being made to Schedules 13G, as amended, in file with the SEC with respect to the Registrant's voting securities (the information contained in such schedules 13G, as amended, not being incorporated herein by reference).

(b) Security ownership of management:

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

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 11, 2017, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2016, relating to its Annual Meeting of Shareholders held on May 12, 2016.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2016:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(1)		
Equity compensation plans approved by security holders (2)	—	$ —	1,752,979

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long-Term Incentive Plan. At December 31, 2016, 109,806 Restricted Share awards were outstanding. Performance and market-based share awards may be paid out at zero shares at a minimum achievement level; 332,680 shares at target level; or 665,360 shares at a maximum level. Because there is no exercise price associated with restricted shares or performance and market-based share awards, such shares are not included in the weighted-average price calculation.

(2) Includes the Long-Term Incentive Plan approved by shareholders in 1998 and the Non-Employee Director Stock Plan approved by shareholders in 1996. In February 2005, the Board of Directors elected to terminate the Non-Employee Director Stock Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

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

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 11, 2017, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2016, relating to its Annual Meeting of Shareholders held on May 12, 2016.

Item 14. Principal Accounting Fees and Services

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

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 11, 2017, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 31, 2016, relating to its Annual Meeting of Shareholders held on May 12, 2016.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1. Financial Statements (Included in Part II of this report):

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Income for the Years Ended December 31, 2016, 2015 and 2014

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2016, 2015 and 2014

Consolidated Balance Sheets as of December 31, 2016 and 2015

Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014

Consolidated Statements of Equity and Redeemable Noncontrolling Interests for the Years Ended December 31, 2016, 2015 and 2014

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on page 147. The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K pursuant to Item 15(b).

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AVISTA CORPORATION

February 21, 2017
Date

By /s/ Scott L. Morris
Scott L. Morris
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Scott L. Morris Scott L. Morris Chairman of the Board, President and Chief Executive Officer	Principal Executive Officer	February 21, 2017
/s/ Mark T. Thies Mark T. Thies (Senior Vice President, Chief Financial Officer, and Treasurer)	Principal Financial Officer	February 21, 2017
/s/ Ryan L. Krasselt Ryan L. Krasselt (Vice President, Controller and Principal Accounting Officer)	Principal Accounting Officer	February 21, 2017
/s/ Erik J. Anderson Erik J. Anderson	Director	February 21, 2017
/s/ Kristianne Blake Kristianne Blake	Director	February 21, 2017
/s/ Donald C. Burke Donald C. Burke	Director	February 21, 2017
/s/ John F. Kelly John F. Kelly	Director	February 21, 2017
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 21, 2017
/s/ Marc F. Racicot Marc F. Racicot	Director	February 21, 2017

/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 21, 2017
/s/ R. John Taylor R. John Taylor	Director	February 21, 2017
/s/ Janet D. Widmann Janet D. Widmann	Director	February 21, 2017
/s/ Scott H. Maw Scott H. Maw	Director	February 21, 2017

EXHIBIT INDEX

	Previously Filed (1)		
Exhibit	With Registration Number	As Exhibit	
3.1	(with June 30, 2012 Form 10-Q)	3.1	Restated Articles of Incorporation of Avista Corporation, as amended and restated June 6, 2012.
3.2	(with Form 8-K filed as of November 14, 2014)	3.2	Bylaws of Avista Corporation, as amended November 14, 2014.
4.1	2-4077	B-3	Mortgage and Deed of Trust, dated as of June 1, 1939.
4.2	2-9812	4(c)	First Supplemental Indenture, dated as of October 1, 1952.
4.3	2-60728	2(b)-2	Second Supplemental Indenture, dated as of May 1, 1953.
4.4	2-13421	4(b)-3	Third Supplemental Indenture, dated as of December 1, 1955.
4.5	2-13421	4(b)-4	Fourth Supplemental Indenture, dated as of March 15, 1967.
4.6	2-60728	2(b)-5	Fifth Supplemental Indenture, dated as of July 1, 1957.
4.7	2-60728	2(b)-6	Sixth Supplemental Indenture, dated as of January 1, 1958.
4.8	2-60728	2(b)-7	Seventh Supplemental Indenture, dated as of August 1, 1958.
4.9	2-60728	2(b)-8	Eighth Supplemental Indenture, dated as of January 1, 1959.
4.10	2-60728	2(b)-9	Ninth Supplemental Indenture, dated as of January 1, 1960.
4.11	2-60728	2(b)-10	Tenth Supplemental Indenture, dated as of April 1, 1964.
4.12	2-60728	2(b)-11	Eleventh Supplemental Indenture, dated as of March 1, 1965.
4.13	2-60728	2(b)-12	Twelfth Supplemental Indenture, dated as of May 1, 1966.
4.14	2-60728	2(b)-13	Thirteenth Supplemental Indenture, dated as of August 1, 1966.
4.15	2-60728	2(b)-14	Fourteenth Supplemental Indenture, dated as of April 1, 1970.
4.16	2-60728	2(b)-15	Fifteenth Supplemental Indenture, dated as of May 1, 1973.
4.17	2-60728	2(b)-16	Sixteenth Supplemental Indenture, dated as of February 1, 1975.
4.18	2-60728	2(b)-17	Seventeenth Supplemental Indenture, dated as of November 1, 1976.
4.19	2-69080	2(b)-18	Eighteenth Supplemental Indenture, dated as of June 1, 1980.
4.20	(with 1980 Form 10-K)	4(a)-20	Nineteenth Supplemental Indenture, dated as of January 1, 1981.
4.21	2-79571	4(a)-21	Twentieth Supplemental Indenture, dated as of August 1, 1982.
4.22	(with Form 8-K dated September 20, 1983)	4(a)-22	Twenty-First Supplemental Indenture, dated as of September 1, 1983.
4.23	2-94816	4(a)-23	Twenty-Second Supplemental Indenture, dated as of March 1, 1984.

Exhibit	Previously Filed (1) With Registration Number	As Exhibit	
4.24	(with 1986 Form 10-K)	4(a)-24	Twenty-Third Supplemental Indenture, dated as of December 1, 1986.
4.25	(with 1987 Form 10-K)	4(a)-25	Twenty-Fourth Supplemental Indenture, dated as of January 1, 1988.
4.26	(with 1989 Form 10-K)	4(a)-26	Twenty-Fifth Supplemental Indenture, dated as of October 1, 1989.
4.27	33-51669	4(a)-27	Twenty-Sixth Supplemental Indenture, dated as of April 1, 1993.
4.28	(with 1993 Form 10-K)	4(a)-28	Twenty-Seventh Supplemental Indenture, dated as of January 1, 1994.
4.29	(with 2001 Form 10-K)	4(a)-29	Twenty-Eighth Supplemental Indenture, dated as of September 1, 2001.
4.30	333-82502	4(b)	Twenty-Ninth Supplemental Indenture, dated as of December 1, 2001.
4.31	(with June 30, 2002 Form 10-Q)	4(f)	Thirtieth Supplemental Indenture, dated as of May 1, 2002.
4.32	333-39551	4(b)	Thirty-First Supplemental Indenture, dated as of May 1, 2003.
4.33	(with September 30, 2003 Form 10-Q)	4(f)	Thirty-Second Supplemental Indenture, dated as of September 1, 2003.
4.34	333-64652	4(a)33	Thirty-Third Supplemental Indenture, dated as of May 1, 2004.
4.35	(with Form 8-K dated as of December 15, 2004)	4.1	Thirty-Fourth Supplemental Indenture, dated as of November 1, 2004.
4.36	(with Form 8-K dated as of December 15, 2004)	4.2	Thirty-Fifth Supplemental Indenture, dated as of December 1, 2004.
4.37	(with Form 8-K dated as of December 15, 2004)	4.3	Thirty-Sixth Supplemental Indenture, dated as of December 1, 2004.
4.38	(with Form 8-K dated as of December 15, 2004)	4.4	Thirty-Seventh Supplemental Indenture, dated as of December 1, 2004.
4.39	(with Form 8-K dated as of May 12, 2005)	4.1	Thirty-Eighth Supplemental Indenture, dated as of May 1, 2005.
4.40	(with Form 8-K dated as of November 17, 2005)	4.1	Thirty-Ninth Supplemental Indenture, dated as of November 1, 2005.
4.41	(with Form 8-K dated as of April 6, 2006)	4.1	Fortieth Supplemental Indenture, dated as of April 1, 2006.
4.42	(with Form 8-K dated as of December 15, 2006)	4.1	Forty-First Supplemental Indenture, dated as of December 1, 2006.
4.43	(with Form 8-K dated as of April 3, 2008)	4.1	Forty-Second Supplemental Indenture, dated as of April 1, 2008.
4.44	(with Form 8-K dated as of November 26, 2008)	4.1	Forty-Third Supplemental Indenture, dated as of November 1, 2008.
4.45	(with Form 8-K dated as of December 16, 2008)	4.1	Forty-Fourth Supplemental Indenture, dated as of December 1, 2008.
4.46	(with Form 8-K dated as of December 30, 2008)	4.3	Forty-Fifth Supplemental Indenture, dated as of December 1, 2008.
4.47	(with Form 8-K dated as of September 15, 2009)	4.1	Forty-Sixth Supplemental Indenture, dated as of September 1, 2009.
4.48	(with Form 8-K dated as of November 25, 2009)	4.1	Forty-Seventh Supplemental Indenture, dated as of November 1, 2009.
4.49	(with Form 8-K dated as of December 15, 2010)	4.5	Forty-Eighth Supplemental Indenture, dated as of December 1, 2010.
4.50	(with Form 8-K dated as of December 20, 2010)	4.1	Forty-Ninth Supplemental Indenture, dated as of December 1, 2010.

	Previously Filed (1)		
Exhibit	With Registration Number	As Exhibit	
4.51	(with Form 8-K dated as of December 30, 2010)	4.1	Fiftieth Supplemental Indenture, dated as of December 1, 2010.
4.52	(with Form 8-K dated as of February 11, 2011)	4.1	Fifty-First Supplemental Indenture, dated as of February 1, 2011.
4.53	(with Form 8-K dated as of August 16, 2011)	4.1	Fifty-Second Supplemental Indenture, dated as of August 1, 2011.
4.54	(with Form 8-K dated as of December 14, 2011)	4.1	Fifty-Third Supplemental Indenture, dated as of December 1, 2011.
4.55	(with Form 8-K dated as of November 30, 2012)	4.1	Fifty-Fourth Supplemental Indenture, dated as of November 1, 2012.
4.56	(with Form 8-K dated as of August 14, 2013)	4.1	Fifty-Fifth Supplemental Indenture, dated as of August 1, 2013.
4.57	(with Form 8-K dated as of April 18, 2014)	4.1	Fifty-Sixth Supplemental Indenture, dated as of April 1, 2014.
4.58	(with Form 8-K dated as of December 18, 2014)	4.1	Fifty-Seventh Supplemental Indenture, dated as of December 1, 2014.
4.59	(with Form 8-K dated as of December 16, 2015)	4.1	Fifty-Eighth Supplemental Indenture, dated as of December 1, 2015.
4.60	(with Form 8-K dated as of December 16, 2016)	4.1	Fifty-Ninth Supplemental Indenture, dated as of December 1, 2016.
4.61	(with Form 8-K dated as of December 15, 2004)	4.5	Supplemental Indenture No. 1, dated as of December 1, 2004 to the Indenture dated as of April 1, 1998 between Avista Corporation and JPMorgan Chase Bank, N.A.
4.62	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.63	(with Form 8-K dated as of December 15, 2010)	4.1	Loan Agreement between City of Forsyth, Montana and Avista Corporation $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A dated as of December 1, 2010.
4.64	(with Form 8-K dated as of December 15, 2010)	4.3	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A, dated as of December 1, 2010.
4.65	(with Form 8-K dated as of December 15, 2010)	4.2	Loan Agreement between City of Forsyth, Montana and Avista Corporation $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B dated as of December 1, 2010.
4.66	(with Form 8-K dated as of December 15, 2010)	4.4	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B, dated as of December 1, 2010.
4.67	(with June 30, 2012 Form 10-Q)	3.1	Restated Articles of Incorporation of Avista Corporation, as amended and restated June 6, 2012 (see Exhibit 3.1 herein).
4.68	(with Form 8-K filed as of November 14, 2014)	3.2	Bylaws of Avista Corporation, as amended November 14, 2014 (see Exhibit 3.2 herein).
4.69	(Form 10/A)	N/A	Post-Effective Amendment No. 1 on Form 10/A, filed February 26, 2015, to Registration Statement on Form 10, filed September 1952.
10.1	(with Form 8-K dated as of February 11, 2011)	10.1	Credit Agreement, dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, The Bank of New York Mellon, Keybank National Association, and U.S. Bank National Association, as Co-Documentation Agents, Wells Fargo Bank National Association as Syndication Agent and an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.

Exhibit	Previously Filed (1) With Registration Number	As Exhibit	
10.2	(with Form 8-K dated as of April 18, 2014)	10.1	Second Amendment to Credit Agreement, dated as of April 18, 2014, among Avista Corporation, Wells Fargo Bank, National Association, as an Issuing Bank, Union Bank, N.A. as Administrative Agent and an Issuing Bank, and the financial institutions identified hereof as Continuing Lenders and Exiting Lender.
10.3	(with Form 8-K dated as of April 18, 2014)	10.2	Bond Delivery Agreement, dated as of April 18, 2014, between Avista Corporation and Union Bank, N.A.
10.4	(with Form 8-K dated as of December 14, 2011)	10.1	First Amendment and Waiver Thereunder, dated as of December 14, 2011, to the Credit Agreement dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, Wells Fargo Bank National Association as an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.
10.5	(with 2002 Form 10-K)	10(b)-3	Priest Rapids Project Product Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.6	(with 2002 Form 10-K)	10(b)-4	Priest Rapids Project Reasonable Portion Power Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.7	(with 2002 Form 10-K)	10(b)-5	Additional Product Sales Agreement (Priest Rapids Project) executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.8	2-60728	5(g)	Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10.9	2-60728	5(g)-1	Amendment to Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10.10	2-60728	5(h)	Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10.11	2-60728	5(h)-1	Amendment to Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10.12	(with September 30, 1985 Form 10-Q)	1	Settlement Agreement and Covenant Not to Sue executed by the United States Department of Energy acting by and through the Bonneville Power Administration and the Company, dated as of September 17, 1985, describing the settlement of Project 3 litigation.
10.13	(with 1981 Form 10-K)	10(s)-7	Ownership and Operation Agreement for Colstrip Units No. 3 & 4, dated as of May 6, 1981.
10.14	(with 2011 Form 10-K)	10.15	Avista Corporation Executive Deferral Plan. (3)
10.15	(with 2011 Form 10-K)	10.16	Avista Corporation Executive Deferral Plan. (3)(8)
10.16	(with 2011 Form 10-K)	10.17	Avista Corporation Supplemental Executive Retirement Plan. (3)(8)
10.17	(with 2011 Form 10-K)	10.18	Avista Corporation Supplemental Executive Retirement Plan. (3)(8)
10.18	(with 1992 Form 10-K)	10(t)-11	The Company’s Unfunded Supplemental Executive Disability Plan. (3)
10.19	(with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. (3)

Exhibit	Previously Filed (1) With Registration Number	As Exhibit	
10.20	(with 2010 Definitive Proxy Statement filed March 31, 2010)	Appendix A	Avista Corporation Long-Term Incentive Plan. (3)
10.21	(with 2010 Form 10-K)	10.23	Avista Corporation Performance Award Plan Summary. (3)
10.22	(with 2014 Form 10-K)	10.30	Avista Corporation Performance Award Agreement 2014. (3)
10.23	(with 2015 Form 10-K)	10.31	Avista Corporation Performance Award Agreement 2015. (3)
10.24	(2)		Avista Corporation Performance Award Agreement 2016. (3)
10.25	(with Form 8-K dated June 21, 2005)	10.1	Employment Agreement between the Company and Marian Durkin in the form of a Letter of Employment. (3)
10.26	(with Form 8-K dated August 13, 2008)	10.1	Employment Agreement between the Company and Mark T. Thies in the form of a Letter of Employment. (3)
10.27	333-47290	99.1	Non-Officer Employee Long-Term Incentive Plan.
10.28	(with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(5)
10.29	(with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(6)
10.30	(with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(7)
10.31	(with 2010 Form 10-K)		Form of Change of Control Agreement between the Company and its Executive Officers. (3)(7)
10.32	(2)		Avista Corporation Non-Employee Director Compensation.
12	(2)		Statement Re: computation of ratio of earnings to fixed charges.
21	(2)		Subsidiaries of Registrant.
23	(2)		Consent of Independent Registered Public Accounting Firm.
31.1	(2)		Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).
31.2	(2)		Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).
32	(4)		Certification of Corporate Officers (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).
101	(2)		The following financial information from the Annual Report on Form 10 K for the period ended December 31, 2016, formatted in XBRL (Extensible Business Reporting Language) and filed electronically herewith: (i) the Consolidated Statements of Income; (ii) Consolidated Statements of Comprehensive Income; (iii) the Consolidated Balance Sheets; (iv) the Consolidated Statements of Cash Flows; (v) the Consolidated Statements of Equity and Redeemable Noncontrolling Interests; and (vi) the Notes to Consolidated Financial Statements.

(1) Incorporated herein by reference.
(2) Filed herewith.
(3) Management contracts or compensatory plans filed as exhibits to this Form 10-K pursuant to Item 15(b).
(4) Furnished herewith.
(5) Applies to James M. Kensok, David J. Meyer, Kelly O. Norwood, Jason R. Thackston and Dennis P. Vermillion.
(6) Applies to Marian M. Durkin, Karen S. Feltes, Scott L. Morris, and Mark T. Thies.
(7) Applies to executive officers appointed after October 1, 2010. This applies to Kevin J. Christie, Ryan L. Krasselt, Ed D. Schlect and Heather L. Rosentrater.

(8) Applies to executive officers appointed after February 4, 2011. This applies to Kevin J. Christie, Ryan L. Krasselt, Ed D. Schlect and Heather L. Rosentrater.

AVISTA CORPORATION PERFORMANCE AWARD AGREEMENT

This Performance Award Agreement (the "Agreement") is made by and between Avista Corporation, a Washington Corporation (the "Company") and the individual named in section 1 (the "Participant") as designated by the Avista Corporation Compensation and Organization Committee (the "Plan Administrator").

WHEREAS, Performance Awards are granted under the January 19, 2016 amended and restated Avista Corporation Long-Term Incentive Plan (the "Plan"). The terms and conditions of the Performance Awards are set forth below and in the Plan, which is incorporated into this Agreement by reference.

NOW, THEREFORE, in consideration of the premises contained herein and in the Plan, it is agreed as follows:

1. **Terms of Performance Awards**. The terms of the Performance Awards are set forth as follows:

(a) The "Participant" is **(Participant's name)**

(b) The "Grant Date" is February 4, 2016.

(c) The total target number of eligible "Performance Awards" shall be **(# of)** units. "Performance Awards" granted under this Agreement are units that will be reflected in a book account maintained by the Company or a third party administrator during the Performance Cycle, and that will be settled in cash or shares of Avista Corporation Common Stock ("Common Stock") to the extent provided in this Agreement and the Plan.

(d) The "Performance Cycle" is the period beginning on January 1, 2016 and ending on December 31, 2018.

2. **Conditions to Award**. Pursuant to this Award, the number of Performance Awards earned will depend upon the Company's performance against specific performance metrics. The performance metrics are (i) Relative Total Shareholder Return, which accounts for **(# of)** units of the total target award as set forth in section 1(c), and (ii) Cumulative Earnings Per Share ("CEPS") which accounts for **(# of)** units of the total target award set forth in section 1(c). The total number of shares of Stock that will be issued in the settlement of this Award, based upon the Company's satisfaction of the metrics, will be determined by multiplying the Target Number of units allocated for each metric set forth in this section 2 by the applicable Payout Factor in accordance with the provisions of Exhibit 1 and Exhibit 2, which is attached to and forms a part of this Agreement.

3. **Settlement of Performance Awards**. The Company shall deliver to the Participant one share of Common Stock (or cash equal to the Fair Market Value of one share of Common Stock) for each Performance Award earned by the Participant, as determined in accordance with the provisions of Exhibit 1 and Exhibit 2, which is attached to and forms a part of this Agreement. The earned Performance Award payable to the Participant shall be paid in shares of Common Stock or in cash (based on the Fair Market Value of the Common Stock as of the date the Plan Administrator certifies the attainment of the

performance goals), or in a combination of the two, as determined by the Plan Administrator in its sole discretion, except that cash may be distributed in lieu of any fractional share of Common Stock.

All Performance Awards and any Dividend Equivalents (as described in Section 5 below) earned by a Participant under this Agreement are subject to the Recoupment Policy adopted by the Company's Board of Directors as amended from time to time ("Recoupment Policy"). If a Participant becomes subject to the Recoupment Policy any Performance Award and associated Dividend Equivalent may be forfeited in whole or in part and all or part of any distribution payable to a Participant or his or her beneficiary under this Agreement may be recovered by the Company pursuant to the Recoupment Policy.

4. **Time of Payment**. Except as otherwise provided in this Agreement, payment of Performance Awards earned will be delivered as soon as feasible after the end of the Performance Cycle and after the Plan Administrator certifies the attainment of the performance goals.

5. **Dividend Equivalent Rights**. Any Performance Awards may, in the Plan Administrator's discretion, earn Dividend Equivalent Rights. In respect of any Performance Award that is outstanding on the dividend record date for Common Stock, the Participant may be credited with an amount equal to the cash distributions that would have been paid on the shares of Common Stock covered by such Award had such covered shares been issued and outstanding on such dividend record date. Dividend Equivalent Rights are to be paid in cash based on the total number of Performance Awards earned at the end of the Performance Cycle and delivered as soon as feasible after the Performance Cycle and after the Plan Administrator certifies the attainment of the performance goals. Dividend Equivalent Rights are subject to all applicable taxes, which are the responsibility of the Participant. The Dividend Equivalent Rights in respect of any Performance Awards that are not earned as of the end of a Performance Cycle, shall be forfeited as of the end of the Performance Cycle.

6. **Termination of Employment during Performance Cycle**. Except as otherwise provided in section 7, this section 6 shall apply if the Participant's employment terminates during a Performance Cycle. If the Participant's employment with the Company and/or Subsidiaries terminates during the Performance Cycle because of Retirement, Disability, or Death, the Participant shall be entitled to a prorated value of the Performance Award earned in accordance with Exhibit 1 and Exhibit 2, determined at the end of the Performance Cycle, and based on the ratio of the number of whole months the Participant was employed during the Performance Cycle to the total number of months in the Performance Cycle (36). If a Participant's employment or services with the Company and/or Subsidiaries terminate on or as of the last day of a Performance Cycle, such Participant will be deemed to have terminated after the end of such Performance Cycle. If the Participant's employment with the Company and/or Subsidiaries terminates during the Performance Cycle for any reason other than Retirement, Disability, or Death, the Performance Award granted under this Agreement will be forfeited on the Date of Termination (as defined in section 9(b)); provided, however, that in such circumstances, the Plan Administrator, in its sole discretion, may determine that the Participant will be entitled to receive a prorated or other portion of the Performance Award. In case of termination for Cause, the Performance Award granted shall automatically terminate upon first notification to the Participant of such termination, unless the Plan Administrator determines otherwise. If a Participant's employment with the Company is suspended pending an investigation of whether the Participant shall be terminated for Cause, all the Participant's rights under any Award likewise shall be suspended during the period of investigation. The effect of a Company-approved leave of absence on the terms and conditions of an Award shall be determined by the Plan Administrator, in its sole discretion.

7. **Change in Control**. If a Change in Control occurs during the Performance Cycle, and the Participant's Date of Termination (as defined in section 9(b)) does not occur before the Change in Control date, the Participant shall be entitled to a prorated value of the Performance Award that would have been earned by the Participant in accordance with Exhibit 1 and Exhibit 2, determined as of the date of the Change in Control, prorated based on the ratio of the number of whole months the Participant is employed during the Performance Cycle through the date of the Change in Control, to the total number of months in the Performance Cycle; provided, however, that a Payout Factor of at least 100% as set forth

in Exhibit 1 and Exhibit 2 for the Performance Cycle shall be deemed to have been achieved as of the date of the Change in Control. Notwithstanding the provisions of sections 3 (with the exception of the application of the Recoupment Policy), 4, and 5, the value of the Performance Award, and any Dividend Equivalent Right, earned in accordance with the foregoing provisions of this section shall be delivered to the Participant in a lump sum cash payment as soon as feasible after the occurrence of a Change in Control, with the value of a Performance Award equal to the Fair Market Value of a share of Common Stock determined under the provision of section 3 as of the date of the Change in Control. Distributions to the Participant under sections 3 and 5 shall not be affected by payments under this section, except that the number of Performance Awards and Dividend Equivalent Rights earned by and payable to the Participant shall be reduced by the number of Performance Awards and Dividend Equivalent Rights with respect to which payment was made to the Participant under this section.

8. **Taxes**. The Participant is liable for any and all taxes, including withholding taxes, arising out of the grant, vesting, payment or settlement of any Performance Awards and Dividend Equivalent Rights. The Company shall have the right to require the Participant to remit to the Company, or to withhold awarded shares of Common Stock, or from any Dividend Equivalent Rights or other amounts due to the Participant, as compensation or otherwise, an amount sufficient to satisfy all federal, state and local withholding tax requirements.

9. **Definitions**. For purposes of this Agreement, the terms used in this Agreement shall be subject to the following:

(a) Change in Control. The term "Change in Control" is defined in section 2.4 of the amended and restated Avista Corp. Long Term Incentive Plan.

(b) Date of Termination. The Participant’s "Date of Termination" shall be the first day occurring on or after the Grant Date on which the Participant is not employed by the Company or any Subsidiary, regardless of the reason for the termination of employment; provided that a termination of employment shall not be deemed to occur by reason of a transfer of the Participant between the Company and a Subsidiary or between two Subsidiaries; and further provided that the Participant’s employment shall not be considered terminated while the Participant is on a leave of absence from the Company or a Subsidiary approved by the Participant’s employer. If, as a result of a sale or other transaction, the Participant’s employer ceases to be a Subsidiary (and the Participant’s employer is or becomes an entity that is separate from the Company), and the Participant is not, at the end of the 30-day period following the transaction, employed by the Company or an entity that is then a Subsidiary, then the occurrence of such transaction shall be treated as the Participant’s Date of Termination caused by the Participant being discharged by the employer.

(c) Disability. ‘‘Disability’’ means ‘‘disability’’ as that term is defined for purposes of the Company’s Long Term Disability Plan or other similar successor plan applicable to employees.

(d) Retirement. "Retirement" of the Participant shall mean retirement as of the individual’s retirement date under the Retirement Plan for Employees of Avista Corporation or other similar successor plan applicable to employees.

10. **Assignability**. No Performance Award or Dividend Equivalent Right granted or awarded under the Plan may be assigned or transferred by the Participant other than by will or by the applicable laws of descent and distribution, and, during the Participant’s lifetime, settlements of such Awards may be payable only to the Participant or a permitted assignee or transferee of the Participant (as provided below). Notwithstanding the foregoing, the Plan Administrator, in its sole discretion, may permit such assignment or transfer and may permit a Participant of such Performance Awards or Dividend Equivalent Rights to designate a beneficiary who may receive compensation settlement under the Performance

Award after the Participant's death; provided, however, that any amount so assigned or transferred shall be subject to all the same terms and conditions contained in this Agreement.

11. **General**

11.1 **Award Agreements**. Performance Awards granted under the Plan shall be evidenced by a written agreement that shall contain such terms, conditions, limitations and restrictions as the Plan Administrator shall deem advisable and that are not inconsistent with the Plan.

11.2 **Continued Employment or Services; Rights in Awards**. Nothing contained in this Agreement, the Plan, or any action of the Plan Administrator taken under the Plan or this Agreement shall be construed as giving any Participant or employee of the Company any right to be retained in the employ of the Company or any Subsidiary or to limit the Company's or any Subsidiary's right to terminate the employment or services of the Participant.

11.3 **Registration**. At the present time, the Company has an effective registration statement with respect to the shares. The Company intends to maintain this registration but has no obligation to do so. In the event that such registration ceases to be effective, the Participant will not receive a Performance Award settlement or payment unless exemptions from registration under federal and state securities laws are available; such exemptions from registration are very limited and might be unavailable. **By accepting the Agreement, the Participant hereby acknowledges that he/she has read the section of the Plan and this Agreement entitled Registration.**

11.4 **No Rights as a Shareholder**. No Award under this Agreement shall entitle the Participant to any dividends (except to the extent provided in an award of Dividend Equivalent Rights), voting or any other right of a shareholder unless and until the date of issuance under the Plan of the shares that are the subject of such Performance Award, are free of all applicable restrictions.

11.5 **Compliance with Laws and Regulations**. Notwithstanding anything in the Plan to the contrary, the Board of Directors, in its sole discretion, may bifurcate the Plan so as to restrict, limit or condition the use of any provision of the Plan to Participants who are officers or directors subject to Section 16 of the Exchange Act without so restricting, limiting or conditioning the Plan with respect to other Participants.

11.6 **Severability**. The invalidity or unenforceability of any provision of this Agreement shall not affect the validity and enforceability of any other provision of this Agreement. If any provision of the Agreement is determined to be invalid, illegal or unenforceable in any jurisdiction, or as to any person, or would disqualify any Performance Award under any law deemed applicable by the Plan Administrator, such provision shall be construed or deemed amended by the Plan Administrator to conform to applicable laws, or, if the Plan Administrator determines that the provision cannot be so construed or deemed amended without materially altering the intent of the Plan or the Performance Award, such provision shall be stricken as to such jurisdiction, person or Performance Award, and the remainder of the Agreement and any such Performance Award shall remain in full force and effect.

12. **Administration**. The authority to manage and control the operation and administration of this Agreement shall be vested in the Plan Administrator, and the Plan Administrator shall have all powers with respect to this Agreement as it has with respect to the Plan. Any interpretation of the Agreement by the Plan Administrator and any decision made by it with respect to the Agreement are final and binding.

13. **Construction**. This Agreement is subject to and shall be construed in accordance with the Plan, the terms of which are explicitly made applicable hereto. Unless otherwise defined herein, capitalized terms in this Agreement shall have the same definitions as set forth in the Plan. In the event of any conflict between the provisions hereof and those of the Plan, the provisions of the Plan shall govern.

14. **Amendment**. This Agreement may be amended by written agreement of the Participant and the Company, without the consent of any other person.

15. **Governing Law**. The validity, construction, interpretation and enforceability of this Agreement shall be determined and governed by the laws of the State of Washington without giving effect to the principles of conflicts of laws. For the purpose of litigating any dispute that arises under this Agreement, the parties hereby consent to exclusive jurisdiction in Washington State and agree that such litigation shall be conducted in the courts of Spokane County, Washington or the federal courts of the United States for the eastern district of Washington.

16. **Successors**. The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise to all or substantially all of the business and/or assets of the Company) to agree in writing to assume the Company's obligations under this Agreement and to perform such obligations in the same manner and to the same extent that the Company is required to perform them. As used in this Agreement, "Company" shall mean the Company and any successor to its business and/or assets that assumes and agrees to perform the Company's obligations under the Agreement by operation of law or otherwise.

IN WITNESS WHEREOF, the Participant has executed this Agreement, and the Company has caused these presents to be executed in its name and on its behalf, all effective as of the Grant Date.

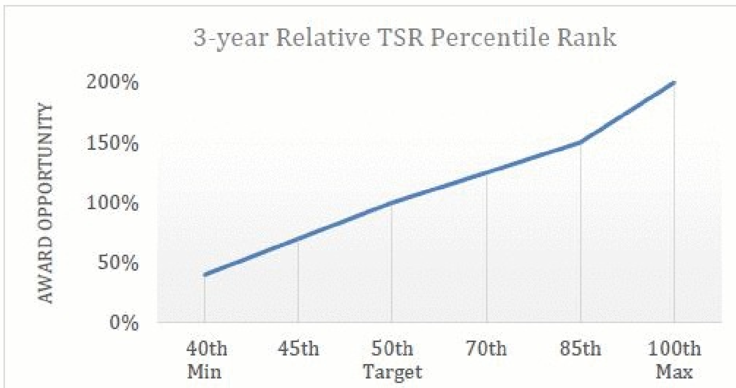
AVISTA CORPORATION

By: Scott L. Morris
Chairman of the Board, President and Chief Executive Officer

EXHIBIT 1

Performance Award Plan
Relative Total Shareholder Return Metric and Goals
2016 - 2018 Performance Cycle

The following graph and table represent the relationship between the Company's relative three-year Total Shareholder Return ("TSR") commencing January 1, 2016 and ending December 31, 2018 and the target award opportunity. The number of shares delivered at the end of the three-year Performance Cycle can range from zero to 200% of the target number of units allocated under this metric. The actual issuance of shares depends on Avista's three-year TSR performance compared to the returns of the peer companies reported in the S&P 400 Utilities Index and how we rank among them. To receive 100% of the Award allocated under this metric, Avista must perform at the 50th percentile among the companies in the S&P
400 Utilities Index. To receive 200% of the Award, Avista must rank at the 100th percentile. If Avista ranks below the 40th percentile, no stock awards or cash Dividend Equivalent Rights will be earned. Dividend
Equivalent Rights are calculated and paid out in cash when and to the extent the Performance Awards are issued. The following graph demonstrates the relationship between TSR ranking and various payout factors. Performance Awards are interpolated on a straight line for performance results between the figures shown.



	Relative TSR Percentile	**Payout Factor**
Maximum	100th	200%
	85th	150%
	70th	125%
Target	50th	100%
	45th	70%
Threshold	40th	40%
	<40th	No Award

TSR is calculated using S&P Research Insight and reflects share price appreciation plus the impact of dividend distributions and the reinvestment of such dividends. To compute the TSR, an adjusted price is calculated by applying a monthly return factor to the average closing share prices on the last trading day of November and December for the start and end of the Performance Cycle.

From one year to the next, if S&P drops a company out of the index and adds another, the new company will be included in the ranking and the dropped company will be excluded. When a new company is added, they will be added to the ranking as if they had been in the ranking from the beginning – provided that there is pricing and dividend data at the beginning of the cycle. When a company is dropped everything related to that company will be excluded from the ranking as if the company was never part of the ranking.

Settlement Formula Example:
Assuming that 970 Performance Award units were allocated under this metric at the beginning of the three-year Performance Cycle and Avista's TSR ranked at the 45th percentile after the three-year Performance Cycle, the Participant would receive 70% of 970 or 679 shares of Avista common stock plus
cash dividend equivalents.

Payout Factor (% of Target)		Target Number of Performance Awards Granted		Final Number of Common Stocks Issued
70%	X	970	=	679 shares plus cash dividends

Percentile Ranking Methodology:
The percentile rank is calculated using the PERCENTRANK function in MS Excel, excluding Avista from the list and rounding all results to the nearest whole percentile.

The calculation can be replicated by arranging the TSR data from highest to lowest for all peers except Avista. A percentile ranking is calculated for each data point assuming 100.0th %ile for the highest data point, 0.0 %ile for the lowest data point, and the corresponding percentile for every other data point with an equal difference in percentile ranking for each data point. The TSR for Avista is calculated by determining Avista's rank in the list and interpolating between the percentile rankings for the companies immediately above and below based on the differences in TSR. An example, based on sample data is as follows:

Company Ranking	TSR	Percentile Rank
1	201.6%	100.0%
2	135.9%	98.2%
47 (ABC Corp)	20.3%	17.8%
48 (XYZ Corp)	16.0%	16.0%
56	-3.3%	1.7%
57	-10.5%	0.0%

If a company's TSR is 18.9%, the resulting percentile ranking would be 17%, calculated as follows: 17% = 16.0% + [(18.9% - 16.0%) / (20.3% - 16.0%) * (17.8% - 16.0%)]

Total Shareholder Return (TSR) Methodology:
For purposes of this Agreement, a methodology for calculating a total return to shareholder with dividend reinvestment was established. Returns are calculated daily based on stock price changes and dividend payments and then accumulated over the Performance Cycle. Below are additional assumptions used in Avista's calculation for TSR.

General Assumptions:
The starting and ending prices are determined by averaging the closing price on the last trading day of November and the last trading day of December at the beginning and the end of the Performance Cycle.

An example, based on sample data is as follows: the stock price for the start of the Performance Cycle for Avista is $34.90, which is the average of $35.35 (12/31/2014) and $34.45 (11/28/2014). Dividends are reinvested on a daily basis. For this example, a fictional ex-date for dividends per share is used for demonstration purposes. Daily returns are calculated over the performance cycle and added together resulting in the Cumulative TSR for the performance cycle.

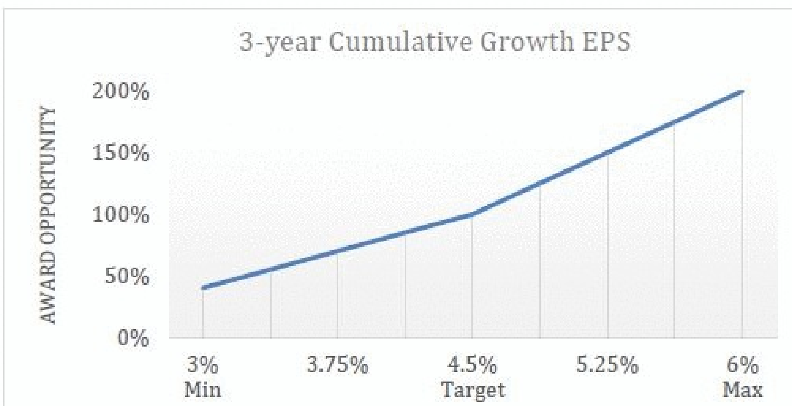
Date	Closing Price	Dividend	Daily TSR
11/21/2014	33.90	0	NA
11/24/2014	33.80	0	(0.2950%)
11/25/2014	34.06	0.3175	1.7086%*
11/26/2014	34.29	0	0.6753%
11/27/2014	34.29	0	0.00%
11/28/2014	34.45	0	0.4666%
Cumulative TSR 11/21/2014 to 11/28/2014			2.5555%

* [(34.06 + 0.3175) / 33.80] -1

EXHIBIT 2

Performance Award Plan
Cumulative Earnings Per Share Metric and Goals
2016 - 2018 Performance Period

The following graph and table represent the relationship between the Company's Cumulative Earnings Per Share ("CEPS") commencing January 1, 2016 and ending December 31, 2018 and the target award opportunity. The number of shares delivered at the end of the three-year Performance Cycle can range from zero to 200% of the target number of units allocated under this metric. The actual issuance of shares depends on Avista's CEPS growth performance over the three-year Performance Cycle. To receive 100% of the Performance Award allocated under this metric, Avista must achieve CEPS compounded growth of 4.50% based on earnings guidance. To receive 200% of the Award, Avista must achieve CEPS compounded growth of 6.00%. If Avista's CEPS compounded growth is less than 3.00%, no stock awards or cash Dividend Equivalent Rights will be earned. Dividend Equivalent Rights are calculated and paid out in cash when and to the extent the Performance Awards are issued. The following graph demonstrates the relationship between CEPS and various payout factors. Performance Awards are interpolated on a straight line for performance results between the figures shown.



	3-Year Cumulative Growth	Payout Factor
Maximum	6.0%	200%
	5.625%	175%
	5.25%	150%
	4.875%	125%
Target	4.5%	100%
	4.125%	85%
	3.75%	70%
	3.375%	55%
Threshold	3%	40%
	<3%	No Award

Performance is tracked over a three-year Performance Cycle thereby focusing on sustainability.

The performance metric CEPS provides for Performance Awards if the Company's cumulative EPS grows at a certain rate on a compounded annual basis. Cumulative EPS is fully diluted earnings per share determined in accordance with generally accepted accounting principles, and may be adjusted to remove the effects of such items as regulatory charges, income tax legislative changes and/or items of a non- routine or items of an extraordinary nature as determined by the Plan Administrator.

Settlement Formula Example:
Assuming that 485 Performance Award units were allocated under this metric at the beginning of the Performance Cycle and Avista's cumulative EPS grew 4.875% over three years, the Participant would receive 125% of 485 or 607 shares of Avista common stock plus dividend equivalents in cash.

Payout Factor (% of Target)		Target Number of Performance Awards Granted		Number of Common Stocks Issued
125%	X	485	=	607 shares plus cash dividends

Using the example formulas in Exhibit 1 and Exhibit 2, the Participant would receive in total 88% of 1,455 (total target # of Performance Awards granted) or 1,286 Shares of Common Stock plus cash dividend equivalents.

	Payout Factor (% of Target)		Target Number of Performance Awards Granted		Number of Common Stocks Issued
TSR	70%	X	970	=	679
CEPS	125%	X	485	=	607
Total	**88%**	**X**	**1,455**	**=**	**1,286**

ACCEPTANCE AND ACKNOWLEDGMENT

I, a resident of the state of___, accept the Performance Award described in this Agreement and in the Plan, and acknowledge that I have received a copy of this Agreement and the Plan. I have read and understand the Plan, and I hereby make the representations, warranties and acknowledgments, and undertake the indemnity and other obligations, therein specified.

Dated: ____________________

____
Social Security Number

____
Signature of Employee

____
Printed Name

Exhibit 10.32

Avista Corporation
Non-Employee Director Compensation - 2016

Prior to August 17, 2016, directors who were not employees of the Company received an annual retainer of $140,000 with $65,000 of the total retainer to be paid in stock each year. Directors had the option of taking the remaining $75,000 in cash, stock or a combination of both cash and stock. The cash portion of the retainer is paid quarterly. Directors were also paid $1,500 for each meeting of the Board or any Committee meeting of the Board. Directors who served as Board Committee Chairs received an additional $7,500 annual retainer, with the exception of the Audit Committee Chair, who received an additional $13,000 annual retainer and the Compensation Committee Chair, who received an additional $10,000 annual retainer. The Lead Director received an additional annual retainer of $20,000.

Each year, the Governance Committee reviews all components of director compensation. During 2016, the Governance Committee engaged Meridian Compensation Partners LLC ("Meridian") to assist in this review. The information provided by Meridian was used to compare the Company's current director compensation with peer companies in the utility industry and general industry companies of similar size (the "Director Peer Group"). The companies comprising the Director Peer Group are those companies in the S&P 400 Utilities Index.

At its August 17, 2016 meeting, the Board reviewed survey results from Meridian regarding current pay practices for director compensation. The Board approved an increase in the annual retainer of an additional $5,000, effective September 1, 2016. The total annual retainer is now $145,000 with $70,000 of the total retainer to be paid in stock each year. Directors will have the option of taking the remaining $75,000 in cash, stock or a combination of both cash and stock. The Committee chair retainers were also increased to the following amounts: Compensation & Organization Committee Chair is now $12,500, Audit Committee Chair is now $15,000, Governance/Nominating Committee Chair is now $10,000, Environmental, Technology & Operations Committee Chair is now $10,000 and the Finance Committee Chair Retainer is now $10,000.

Each director is entitled to reimbursement of reasonable out-of-pocket expenses incurred in connection with meetings of the Board or its Committees and related activities, including director education courses and materials. These expenses include travel to and from the meetings, as well as any expenses they incur while attending the meetings.

The Company has a minimum stock ownership expectation for all Board members. Outside directors are expected to achieve a minimum investment of five times the minimum portion of their equity retainer payable in Company common stock within five years of becoming a Board member, and retain at least that level of investment during his/her tenure as a Board member. Shares previously deferred under the former Non- Employee Director Stock Plan count for purposes of determining whether a director has achieved the ownership expectation. Directors are prohibited from engaging in short-sales, pledging, or hedging the economic interest in their Company shares.

The ownership expectation illustrates the Board's philosophy of the importance of stock ownership for directors to further strengthen the commonality of interest between the Board and shareholders. The Governance Committee annually reviews director holdings to determine whether they meet ownership expectations. All directors currently comply based on their years of service completed on the Board.

There were no annual stock option grants or non-stock incentive plan compensation payments to directors for services in 2016 and none are currently contemplated under the current compensation structure. The Company also does not provide a retirement plan or deferred compensation plan to its directors. Listed below is compensation paid to each non-employee director who served during any part of the 2016 fiscal year.

Exhibit 12

AVISTA CORPORATION

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

	Years Ended December 31				
	2016	2015	2014	2013	2012
Fixed charges, as defined:					
Interest charges	$ 86,897	$ 80,613	$ 74,025	$ 73,772	$ 71,843
Amortization of debt expense and premium - net	3,391	3,415	3,635	3,813	3,803
Interest portion of rentals	1,324	1,287	1,187	1,146	1,294
Total fixed charges	$ 91,612	$ 85,315	$ 78,847	$ 78,731	$ 76,940
Earnings, as defined:					
Pre-tax income from continuing operations	$ 215,402	$ 185,619	$ 192,106	$ 162,347	$ 116,567
Add (deduct):					
Capitalized interest	(2,651)	(3,546)	(3,924)	(3,676)	(2,401)
Total fixed charges above	91,612	85,315	78,847	78,731	76,940
Total earnings	$ 304,363	$ 267,388	$ 267,029	$ 237,402	$ 191,106
Ratio of earnings to fixed charges	3.32	3.13	3.39	3.02	2.48

AVISTA CORPORATION

SUBSIDIARIES OF REGISTRANT

Subsidiary	State or Country of Incorporation
Avista Capital, Inc.	Washington
Avista Development, Inc.	Washington
Avista Energy, Inc.	Washington
Avista Northwest Resources, LLC	Washington
Pentzer Corporation	Washington
Pentzer Venture Holding II, Inc.	Washington
Bay Area Manufacturing, Inc.	Washington
Advanced Manufacturing and Development, Inc.	California
Avista Capital II	Delaware
Steam Plant Square, LLC	Washington
Steam Plant Brew Pub, LLC	Washington
Courtyard Office Center, LLC	Washington
Alaska Energy and Resources Company	Alaska
Alaska Electric Light and Power Company	Alaska
AJT Mining Properties, Inc.	Alaska
Snettisham Electric Company	Alaska
Salix, Inc.	Washington

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-33790, 333-126577, 333-179042 and 333-208986 on Form S-8 and in Registration Statement Nos. 333-187306 and 333-209714 on Form S-3, relating to the consolidated financial statements of Avista Corporation and subsidiaries, and the effectiveness of Avista Corporation's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Avista Corporation for the year ended December 31, 2016.

/s/ Deloitte & Touche LLP

Seattle, Washington

February 21, 2017

Exhibit 31.1

CERTIFICATION

I, Scott L. Morris, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/ Scott L. Morris

Scott L. Morris
Chairman of the Board, President
and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2017

/s/ Mark T. Thies

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

Exhibit 32

AVISTA CORPORATION

CERTIFICATION OF CORPORATE OFFICERS

(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the

Sarbanes-Oxley Act of 2002)

Each of the undersigned, Scott L. Morris, Chairman of the Board, President and Chief Executive Officer of Avista Corporation (the "Company"), and Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Annual Report on Form 10-K for the year ended December 31, 2016 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 21, 2017

/s/ Scott L. Morris

Scott L. Morris
Chairman of the Board, President
and Chief Executive Officer

/s/ Mark T. Thies

Mark T. Thies
Senior Vice President,
Chief Financial Officer, and Treasurer

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

Form 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE QUARTERLY PERIOD ENDED June 30, 2017 OR

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

Commission file number 1-3701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

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

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

None

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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.

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

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

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

As of July 31, 2017, 64,411,244 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

AVISTA CORPORATION
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Forward-Looking Statements

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

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

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

Forward-looking statements (including those made in this Quarterly Report on Form 10-Q) are subject to a variety of risks, uncertainties and other factors. Most of these factors are beyond our control and may have a significant effect on our operations, results of operations, financial condition or cash flows, which could cause actual results to differ materially from those anticipated in our statements. Such risks, uncertainties and other factors include, among others:

Financial Risk

- weather conditions (temperatures, precipitation levels and wind patterns), which affect both energy demand and electric generating capability, including the effect of precipitation and temperature on hydroelectric resources, the effect of wind patterns on wind-generated power, weather-sensitive customer demand, and similar effects on supply and demand in the wholesale energy markets;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions and the global economy;
- changes in interest rates that affect borrowing costs, our ability to effectively hedge interest rates for anticipated debt issuances, variable interest rate borrowing and the extent to which we recover interest costs through retail rates collected from customers;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement benefit plans, which can affect future funding obligations, pension and other postretirement benefit expense and the related liabilities;
- deterioration in the creditworthiness of our customers;
- the outcome of legal proceedings and other contingencies;
- economic conditions in our service areas, including the economy's effects on customer demand for utility services;
- declining energy demand related to customer energy efficiency and/or conservation measures;
- changes in the long-term global and our utilities' service area climates, which can affect, among other things, customer demand patterns and the volume and timing of streamflows to our hydroelectric resources;

Utility Regulatory Risk

- state and federal regulatory decisions or related judicial decisions that affect our ability to recover costs and earn a reasonable return including, but not limited to, disallowance or delay in the recovery of capital investments, operating costs and commodity costs and discretion over allowed return on investment;
- possibility that our integrated resource plans for electric and natural gas will not be acknowledged by the state commissions;

Energy Commodity Risk

- volatility and illiquidity in wholesale energy markets, including the availability of willing buyers and sellers, changes in wholesale energy prices that can affect operating income, cash requirements to purchase electricity and natural gas, value received for wholesale sales, collateral required of us by counterparties in wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;
- default or nonperformance on the part of any parties from whom we purchase and/or sell capacity or energy;
- potential environmental regulations affecting our ability to utilize or resulting in the obsolescence of our power supply resources;

Operational Risk

- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, snow and ice storms, that can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies and support services;
- explosions, fires, accidents, mechanical breakdowns or other incidents that may impair assets and may disrupt operations of any of our generation facilities, transmission, and electric and natural gas distribution systems or other operations and may require us to purchase replacement power;
- wildfires caused by our electric transmission or distribution systems that may result in public injuries or property damage;
- public injuries or damage arising from or allegedly arising from our operations;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- terrorist attacks, cyber attacks or other malicious acts that may disrupt or cause damage to our utility assets or to the national or regional economy in general, including any effects of terrorism, cyber attacks or vandalism that damage or disrupt information technology systems;
- work force issues, including changes in collective bargaining unit agreements, strikes, work stoppages, the loss of key executives, availability of workers in a variety of skill areas, and our ability to recruit and retain employees;
- increasing costs of insurance, more restrictive coverage terms and our ability to obtain insurance;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- increasing health care costs and cost of health insurance provided to our employees and retirees;
- third party construction of buildings, billboard signs, towers or other structures within our rights of way, or placement of fuel receptacles within close proximity to our transformers or other equipment, including overbuild atop natural gas distribution lines;
- the loss of key suppliers for materials or services or disruptions to the supply chain;
- adverse impacts to our Alaska operations that could result from an extended outage of its hydroelectric generating resources or their inability to deliver energy, due to their lack of interconnectivity to any other electrical grids and the extensive cost of replacement power (diesel);
- changing river regulation at hydroelectric facilities not owned by us, which could impact our hydroelectric facilities downstream;

Compliance Risk

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

Technology Risk

- cyber attacks on us or our vendors or other potential lapses that result in unauthorized disclosure of private information, which could result in liabilities against us, costs to investigate, remediate and defend, and damage to our reputation;

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

Strategic Risk

- growth or decline of our customer base and the extent to which new uses for our services may materialize or existing uses may decline, including, but not limited to, the effect of the trend toward distributed generation at customer sites;
- the potential effects of negative publicity regarding business practices, whether true or not, which could result in litigation or a decline in our common stock price;
- changes in our strategic business plans, which may be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses and the extent of our business development efforts where potential future business is uncertain;
- non-regulated activities may increase earnings volatility;
- failure to complete the proposed merger transaction could negatively impact the market price of Avista Corp.'s common stock or result in termination fees that could have a material adverse effect on our results of operations, financial condition, and cash flows;
- the announced merger transaction could result in shareholder class action lawsuits against the Company, its management team and board of directors;

External Mandates Risk

- changes in environmental laws, regulations, decisions and policies, including present and potential environmental remediation costs and our compliance with these matters;
- the potential effects of legislation or administrative rulemaking at the federal, state or local levels, including possible effects on our generating resources of restrictions on greenhouse gas emissions to mitigate concerns over global climate changes;
- political pressures or regulatory practices that could constrain or place additional cost burdens on our distribution systems through accelerated adoption of distributed generation or electric-powered transportation or on our energy supply sources, such as campaigns to halt coal-fired power generation and opposition to other thermal generation, wind turbines or hydroelectric facilities;
- wholesale and retail competition including alternative energy sources, growth in customer-owned power resource technologies that displace utility-supplied energy or that may be sold back to the utility, and alternative energy suppliers and delivery arrangements;
- failure to identify changes in legislation, taxation and regulatory issues which are detrimental or beneficial to our overall business;
- policy and/or legislative changes resulting from the new presidential administration in various regulated areas, including, but not limited to, potential tax reform, environmental regulation and healthcare regulations; and
- the risk of municipalization in any of our service territories.

Our expectations, beliefs and projections are expressed in good faith. We believe they are reasonable based on, without limitation, an examination of historical operating trends, our records and other information available from third parties. There can be no assurance that our expectations, beliefs or projections will be achieved or accomplished. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for us to predict all such factors, nor can we assess the effect of each such factor on our business or the extent that any such factor or combination of factors may cause actual results to differ materially from those contained in any forward-looking statement.

Available Information

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

PART I. Financial Information

Item 1. Condensed Consolidated Financial Statements

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

Dollars in thousands, except per share amounts
(Unaudited)

	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Operating Revenues:				
Utility revenues	$ 308,729	$ 312,888	$ 739,266	$ 725,681
Non-utility revenues	5,772	5,950	11,705	11,330
Total operating revenues	314,501	318,838	750,971	737,011
Operating Expenses:				
Utility operating expenses:				
Resource costs	102,751	109,815	268,337	271,534
Other operating expenses	81,965	78,666	156,449	154,445
Depreciation and amortization	42,643	39,678	84,628	78,870
Taxes other than income taxes	23,802	22,615	56,464	52,000
Non-utility operating expenses:				
Other operating expenses	7,086	6,281	13,265	12,106
Depreciation and amortization	157	192	345	380
Total operating expenses	258,404	257,247	579,488	569,335
Income from operations	56,097	61,591	171,483	167,676
Interest expense	23,670	21,318	47,215	42,591
Interest expense to affiliated trusts	200	154	385	292
Capitalized interest	(890)	(837)	(1,614)	(1,751)
Other income-net	(1,656)	(3,041)	(4,757)	(5,463)
Income before income taxes	34,773	43,997	130,254	132,007
Income tax expense	13,051	16,710	46,395	47,055
Net income	21,722	27,287	83,859	84,952
Net loss (income) attributable to noncontrolling interests	49	(33)	28	(49)
Net income attributable to Avista Corp. shareholders	$ 21,771	$ 27,254	$ 83,887	$ 84,903
Weighted-average common shares outstanding (thousands), basic	64,401	63,386	64,382	62,995
Weighted-average common shares outstanding (thousands), diluted	64,553	63,783	64,511	63,368
Earnings per common share attributable to Avista Corp. shareholders:				
Basic	$ 0.34	$ 0.43	$ 1.30	$ 1.35
Diluted	$ 0.34	$ 0.43	$ 1.30	$ 1.34
Dividends declared per common share	$ 0.3575	$ 0.3425	$ 0.7150	$ 0.6850

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

Dollars in thousands
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Net income	$ 21,722	$ 27,287	$ 83,859	$ 84,952
Other Comprehensive Income (Loss):				
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $99, $76, $197 and $(587) respectively	183	140	366	(1,089)
Total other comprehensive income (loss)	183	140	366	(1,089)
Comprehensive income	21,905	27,427	84,225	83,863
Comprehensive loss (income) attributable to noncontrolling interests	49	(33)	28	(49)
Comprehensive income attributable to Avista Corporation shareholders	$ 21,954	$ 27,394	$ 84,253	$ 83,814

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

	June 30, 2017	December 31, 2016
Assets:		
Current Assets:		
Cash and cash equivalents	$ 13,410	$ 8,507
Accounts and notes receivable-less allowances of $5,607 and $5,026, respectively	133,946	180,265
Regulatory asset for energy commodity derivatives	13,982	11,365
Materials and supplies, fuel stock and stored natural gas	61,187	53,314
Income taxes receivable	35,808	48,265
Other current assets	62,403	49,625
Total current assets	320,736	351,341
Net Utility Property:		
Utility plant in service	5,617,233	5,506,499
Construction work in progress	169,000	150,474
Total	5,786,233	5,656,973
Less: Accumulated depreciation and amortization	1,558,773	1,509,473
Total net utility property	4,227,460	4,147,500
Other Non-current Assets:		
Investment in affiliated trusts	11,547	11,547
Goodwill	57,672	57,672
Other property and investments-net and other non-current assets	79,487	72,224
Total other non-current assets	148,706	141,443
Deferred Charges:		
Regulatory assets for deferred income tax	118,984	109,853
Regulatory assets for pensions and other postretirement benefits	234,046	240,114
Other regulatory assets	134,533	135,751
Regulatory asset for interest rate swaps	168,084	161,508
Non-current regulatory asset for energy commodity derivatives	15,023	16,919
Other deferred charges	5,432	5,326
Total deferred charges	676,102	669,471
Total assets	$ 5,373,004	$ 5,309,755

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

Dollars in thousands
(Unaudited)

	June 30, 2017	December 31, 2016
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 69,165	$ 115,545
Current portion of long-term debt and capital leases	277,814	3,287
Short-term borrowings	136,398	120,000
Energy commodity derivative liabilities	8,308	7,035
Accrued interest	16,128	15,869
Accrued taxes other than income taxes	33,169	33,374
Deferred natural gas costs	28,973	30,820
Current portion of pensions and other postretirement benefits	11,235	10,994
Current interest rate swap derivative liabilities	36,507	6,025
Other current liabilities	64,417	64,579
Total current liabilities	682,114	407,528
Long-term debt and capital leases	1,403,064	1,678,717
Long-term debt to affiliated trusts	51,547	51,547
Regulatory liability for utility plant retirement costs	280,580	273,983
Pensions and other postretirement benefits	219,584	226,552
Deferred income taxes	886,727	840,928
Non-current interest rate swap derivative liabilities	336	28,705
Other non-current liabilities, regulatory liabilities and deferred credits	162,158	153,319
Total liabilities	3,686,110	3,661,279
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Equity:		
Avista Corporation Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 64,408,983 and 64,187,934 shares issued and outstanding as of June 30, 2017 and December 31, 2016, respectively	1,075,667	1,075,281
Accumulated other comprehensive loss	(7,202)	(7,568)
Retained earnings	618,708	581,014
Total Avista Corporation shareholders' equity	1,687,173	1,648,727
Noncontrolling Interests	(279)	(251)
Total equity	1,686,894	1,648,476
Total liabilities and equity	$ 5,373,004	$ 5,309,755

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

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

	2017	2016
Operating Activities:		
Net income	$ 83,859	$ 84,952
Non-cash items included in net income:		
Depreciation and amortization	86,790	81,071
Deferred income tax provision and investment tax credits	36,169	56,652
Power and natural gas cost amortizations, net	6,366	9,958
Amortization of debt expense	1,627	1,742
Amortization of investment in exchange power	1,225	1,225
Stock-based compensation expense	2,643	4,236
Equity-related Allowance for Funds Used During Construction (AFUDC)	(3,292)	(4,368)
Pension and other postretirement benefit expense	18,539	19,315
Amortization of Spokane Energy contract	—	7,192
Other regulatory assets and liabilities and deferred debits and credits	(8,831)	(13,169)
Change in decoupling regulatory deferral	10,365	(24,787)
Other	420	5,032
Contributions to defined benefit pension plan	(14,800)	(8,000)
Changes in certain current assets and liabilities:		
Accounts and notes receivable	45,375	50,062
Materials and supplies, fuel stock and stored natural gas	(7,879)	2,510
Collateral posted for derivative instruments	(5,460)	(83,499)
Income taxes receivable	12,457	(1,450)
Other current assets	(3,825)	(4,436)
Accounts payable	(29,435)	(31,484)
Other current liabilities	(3,787)	3,197
Net cash provided by operating activities	228,526	155,951
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(177,714)	(182,815)
Issuance of notes receivable at subsidiaries	(2,500)	(9,668)
Equity and property investments made by subsidiaries	(10,347)	(6,988)
Distributions received from investments	1,915	—
Other	(943)	(7,153)
Net cash used in investing activities	(189,589)	(206,624)

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

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

	2017	2016
Financing Activities:		
Net increase in short-term borrowings	$ 16,000	$ 55,000
Maturity of long-term debt and capital leases	(1,643)	(1,583)
Issuance of common stock, net of issuance costs	1,247	47,173
Cash dividends paid	(46,193)	(43,267)
Other	(3,445)	(3,612)
Net cash provided by (used in) financing activities	(34,034)	53,711
Net increase in cash and cash equivalents	4,903	3,038
Cash and cash equivalents at beginning of period	8,507	10,484
Cash and cash equivalents at end of period	$ 13,410	$ 13,522

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

Avista Corporation

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

	2017	2016
Common Stock, Shares:		
Shares outstanding at beginning of period	64,187,934	62,312,651
Shares issued	221,049	1,391,644
Shares outstanding at end of period	64,408,983	63,704,295
Common Stock, Amount:		
Balance at beginning of period	$ 1,075,281	$ 1,004,336
Equity compensation expense	2,559	3,708
Issuance of common stock, net of issuance costs	1,247	47,173
Payment of minimum tax withholdings for share-based payment awards	(3,420)	(3,027)
Balance at end of period	1,075,667	1,052,190
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(7,568)	(6,650)
Other comprehensive income (loss)	366	(1,089)
Balance at end of period	(7,202)	(7,739)
Retained Earnings:		
Balance at beginning of period	581,014	530,940
Net income attributable to Avista Corporation shareholders	83,887	84,903
Cash dividends paid on common stock	(46,193)	(43,267)
Balance at end of period	618,708	572,576
Total Avista Corporation shareholders' equity	1,687,173	1,617,027
Noncontrolling Interests:		
Balance at beginning of period	(251)	(339)
Net income (loss) attributable to noncontrolling interests	(28)	49
Balance at end of period	(279)	(290)
Total equity	$ 1,686,894	$ 1,616,737

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

The accompanying condensed consolidated financial statements of Avista Corporation (Avista Corp. or the Company) as of and for the interim periods ended June 30, 2017 and June 30, 2016 are unaudited; however, in the opinion of management, the statements reflect all adjustments necessary for a fair statement of the results for the interim periods. All such adjustments are of a normal recurring nature. The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. The Condensed Consolidated Statements of Income for the interim periods are not necessarily indicative of the results to be expected for the full year. These condensed consolidated financial statements do not contain the detail or footnote disclosure concerning accounting policies and other matters which would be included in full fiscal year consolidated financial statements; therefore, they should be read in conjunction with the Company's audited consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2016 (2016 Form 10-K). Please refer to the section “Acronyms and Terms” in the 2016 Form 10-K for definitions of certain terms not defined herein. The acronyms and terms are an integral part of these condensed consolidated financial statements.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

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

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

Basis of Reporting

The condensed consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Intercompany balances were eliminated in consolidation. The accompanying condensed consolidated financial statements include the Company’s proportionate share of utility plant and related operations resulting from its interests in jointly owned plants.

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense. Taxes other than income taxes consisted of the following items for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Utility related taxes	$ 13,552	$ 12,573	$ 35,136	$ 30,938
Property taxes	9,432	9,290	19,838	19,710
Other taxes	818	752	1,490	1,352
Total	$ 23,802	$ 22,615	$ 56,464	$ 52,000

Materials and Supplies, Fuel Stock and Stored Natural Gas

Inventories of materials and supplies, fuel stock and stored natural gas are recorded at average cost for our regulated operations and the lower of cost or net realizable value for our non-regulated operations and consisted of the following as of June 30, 2017 and December 31, 2016 (dollars in thousands):

	June 30, 2017	December 31, 2016
Materials and supplies	$ 41,492	$ 40,700
Fuel stock	5,921	4,585
Stored natural gas	13,774	8,029
Total	$ 61,187	$ 53,314

Derivative Assets and Liabilities

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

The Washington Utilities and Transportation Commission (UTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. Realized benefits and costs result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rate cases. The resulting regulatory assets have been concluded to be probable of recovery through future rates.

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

For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process.

As of June 30, 2017, the Company has multiple master netting agreements with a variety of entities that allow for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have any agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The Company nets all derivative instruments when allowed by the agreement for presentation in the Condensed Consolidated Balance Sheets.

Fair Value Measurements

Fair value represents the price that would be received when selling an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swaps and foreign currency exchange contracts, are reported at estimated fair value on the Condensed Consolidated Balance Sheets. See Note 8 for the Company's fair value disclosures.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, consisted of the following as of June 30, 2017 and December 31, 2016 (dollars in thousands):

	June 30, 2017	December 31, 2016
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $3,878 and $4,075, respectively	$ 7,202	$ 7,568

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

	Amounts Reclassified from Accumulated Other Comprehensive Loss				
	Three months ended June 30,		Six months ended June 30,		
Details about Accumulated Other Comprehensive Loss Components	2017	2016	2017	2016	Affected Line Item in Statement of Income
Amortization of defined benefit pension items					
Amortization of net prior service cost	$ (299)	$ (311)	$ (598)	$ (622)	(a)
Amortization of net loss	3,638	3,642	$ 7,276	$ 7,284	(a)
Adjustment due to effects of regulation	(3,057)	(3,115)	(6,115)	(8,338)	(a) (b)
	282	216	563	(1,676)	Total before tax
	(99)	(76)	(197)	587	Tax benefit (expense)
	$ 183	$ 140	$ 366	$ (1,089)	Net of tax

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 4 for additional details).

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

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses loss contingencies that do not meet these conditions for accrual if there is a reasonable possibility that a material loss may be incurred. As of June 30, 2017, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 11 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)"

In May 2014, the FASB issued ASU No. 2014-09, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity should identify the various performance obligations in a contract, allocate the transaction price among the performance obligations and recognize revenue when (or as) the entity satisfies each performance obligation. This ASU is effective for periods beginning after December 15, 2017.

The Company has a revenue recognition standard implementation team that is working through implementation issues. The Company has evaluated this standard and is planning to adopt this standard in 2018 upon its effective date. The Company is expecting to use a modified retrospective method of adoption, which would require a cumulative adjustment to opening retained earnings, as opposed to a full retrospective application. Based on work performed to date, the Company has not identified any material cumulative adjustments necessary.

Since the majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers and revenue is recognized as energy is delivered to these customers, the Company does not expect a significant change in operating revenues or net income. The Company is in the process of reviewing and analyzing certain contracts with customers (most of which are related to wholesale sales of power and natural gas) and has not yet identified any significant differences in revenue recognition between current GAAP and ASU No. 2014-09.

During the implementation process, the Company has identified several issues, the most significant of which are as follows based on our current assessment:

Contributions in Aid of Construction – There was the potential that contributions in aid of construction (CIAC) could be recognized as revenue upon the adoption of ASU No. 2014-09. Under current GAAP, CIACs are accounted for as an offset to the cost of utility plant in service. Current preliminary implementation guidance indicates that CIACs will continue to be accounted for as an offset to utility plant in service.

Utility-Related Taxes Collected from Customers – There were questions on the presentation of utility related taxes collected from customers (primarily state excise taxes and city utility taxes) on a gross basis. Under current GAAP, the Company is allowed to record these utility related taxes on a gross basis in revenue when billed to customers with an offset included in taxes other than income taxes in operating expenses. The Company evaluated whether this gross presentation is appropriate under ASU 2014-09 and the Company's preliminary assessment indicates that there will be no material changes to current presentation.

Collectibility - There were questions regarding the requirement that collection of a sale be probable and how, or if, utilities should consider bad debt collection mechanisms (riders, base rate adjustments, etc.) in assessing probability of collection on sales to low income customers. Current preliminary implementation guidance indicates that bad debt collection mechanisms should be considered; therefore, the Company does not expect a change to its current presentation going forward.

The Company is monitoring utility industry implementation guidance as it relates to certain issues to determine if there will be an industry consensus regarding accounting and presentation of these items.

In addition to the issues described above, the Company also expects significant changes to its revenue-related footnote disclosures. The Company continues to evaluate what information would be most useful for users of the financial statements, including information already provided elsewhere in the document outside the footnote disclosures. These additional disclosures could include the disaggregation of revenues by geographic location, type of service, source of revenue or customer class. Also, the Company expects enhanced disclosures regarding its revenue recognition policies and elections.

ASU No. 2016-02 "Leases (Topic 842)."

In February 2016, the FASB issued ASU No. 2016-02. This ASU introduces a new lessee model that requires most leases to be capitalized and shown on the balance sheet with corresponding lease assets and liabilities. The standard also aligns certain of the underlying principles of the new lessor model with those in Topic 606, the FASB's new revenue recognition standard. Furthermore, this ASU addresses other issues that arise under the current lease model; for example, eliminating the required use of bright-line tests in current GAAP for determining lease classification (operating leases versus capital leases). This ASU also includes enhanced disclosures surrounding leases. This ASU is effective for periods beginning on or after December 15, 2018; however, early adoption is permitted. Upon adoption, this ASU must be applied using a modified retrospective approach to the earliest period presented, which will likely require restatements of previously issued financial statements. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. The Company evaluated this standard and determined that it will most likely not early adopt this standard before its effective date in 2019. The Company has formed a lease standard implementation team that is working through the implementation process. The most significant implementation challenge identified thus far relates to identifying a complete population of leases and potential leases under the new lease standard. Also, the Company is monitoring utility industry implementation guidance as it relates to several unresolved issues to determine if there will be an industry consensus, including whether right-of-ways are considered leases. The Company has not yet estimated the potential impact on its future financial condition, results of operations and cash flows.

ASU No. 2016-09 "Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting."

In March 2016, the FASB issued ASU No. 2016-09. This ASU simplified several aspects of the accounting for employee share-based payment transactions including:

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

The Company early adopted this standard during the second quarter of 2016, with a retrospective effective date of January 1, 2016. The adoption of this standard resulted in a recognized income tax benefit of $1.6 million in 2016 associated with excess tax benefits on settled share-based employee payments. Because this standard was adopted in the second quarter of 2016, but had a retrospective effective date of January 1, 2016, the effects from the adoption were reflected in the first quarter of 2016 and the Condensed Consolidated Financial Statements for that quarter were recast from those presented when the financial statements were originally issued.

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

In March 2017, the FASB issued ASU No. 2017-07, which amends the income statement presentation of the components of net period benefit cost for an entity's defined benefit pension and other postretirement plans. Under current GAAP, net benefit cost consists of several components that reflect different aspects of an employer's financial arrangements as well as the cost of benefits earned by employees. These components are aggregated and reported net in the financial statements. ASU No. 2017-07 requires entities to (1) disaggregate the current service-cost component from the other components of net benefit cost (other components) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations.

In addition, only the service-cost component of net benefit cost is eligible for capitalization (e.g., as part of utility plant). This is a change from current practice, under which entities capitalize the aggregate net benefit cost to utility plant when applicable, in accordance with Federal Energy and Regulatory Commission (FERC) accounting guidance. Avista Corp. is a rate-regulated entity and all components of net benefit cost are currently recovered from rate payers as a component of utility plant and under the new ASU these costs will continue to be recovered from rate payers in the same manner over the depreciable lives of utility plant. As all such costs are expected to continue to be recoverable, the components that are no longer eligible to be recorded as a component of plant for GAAP will be recorded as regulatory assets.

This ASU is effective for periods beginning after December 15, 2017 and early adoption is permitted. Upon adoption, entities must use a retrospective transition method to adopt the requirement for separate presentation in the income statement and a prospective transition method to adopt the requirement to limit the capitalization of benefit costs to the service-cost component. The Company does not expect to early adopt this standard and does not expect a material impact on its future financial condition, results of operations or cash flows upon adoption of this standard.

NOTE 3. DERIVATIVES AND RISK MANAGEMENT

The disclosures below in Note 3 apply only to Avista Corp. and its operating division Avista Utilities; AERC and its primary subsidiary AEL&P do not enter into derivative instruments.

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options in order to manage the various risks relating to these commodity price exposures. Avista Corp. has an energy resources risk policy and control procedures to manage these risks.

As part of Avista Corp.'s resource procurement and management operations in the electric business, Avista Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and the use of these resources to capture available economic value. Avista Corp. transacts in wholesale markets by selling and purchasing electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging a portion of the related financial risks. These transactions range from terms of intra-hour up to multiple years.

As part of its resource procurement and management of its natural gas business, Avista Corp. makes continuing projections of its natural gas loads and assesses available natural gas resources including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to Avista Corp.'s distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, Avista Corp. plans and executes a series of transactions to hedge a portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as four natural gas operating years (November through October) into the future. Avista Corp. also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Avista Corp. plans for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event. Avista Corp. generally has more pipeline and storage capacity than what is needed during periods other than a peak day. Avista Corp. optimizes its natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Avista Corp. also optimizes its natural gas storage capacity by purchasing and storing natural gas when prices are traditionally lower, typically in the summer, and withdrawing during higher priced months, typically during the winter. However, if market conditions and prices indicate that Avista Corp. should buy or sell natural gas at other times during the year, Avista Corp. engages in optimization transactions to capture value in the marketplace. Natural gas optimization activities include, but are not limited to, wholesale market sales of surplus natural gas supplies, purchases and sales of natural gas to optimize use of pipeline and storage capacity, and participation in the transportation capacity release market.

The following table presents the underlying energy commodity derivative volumes as of June 30, 2017 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs
Remainder 2017	185	999	7,418	63,423	154	1,129	3,378	43,940
2018	397	307	—	78,488	254	1,244	1,360	46,805
2019	235	737	610	42,775	158	982	1,345	26,590
2020	—	—	910	3,635	—	—	1,430	—
2021	—	—	—	—	—	—	1,049	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents the underlying energy commodity derivative volumes as of December 31, 2016 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs
2017	510	907	15,475	110,380	316	1,552	4,165	73,110
2018	397	—	—	52,755	286	1,244	1,360	15,113
2019	235	—	610	29,475	158	982	1,345	4,020
2020	—	—	910	2,725	—	—	1,430	—
2021	—	—	—	—	—	—	1,060	—
Thereafter	—	—	—	—	—	—	—	—

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

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

Foreign Currency Exchange Derivatives

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

The following table summarizes the foreign currency exchange derivatives that Avista Corp. has outstanding as of June 30, 2017 and December 31, 2016 (dollars in thousands):

	June 30, 2017	December 31, 2016
Number of contracts	24	21
Notional amount (in United States dollars)	$ 7,588	$ 2,819
Notional amount (in Canadian dollars)	10,075	3,754

Interest Rate Derivatives

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. Avista Corp. hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swap derivatives and U.S. Treasury lock agreements. These interest rate swap derivatives and U.S. Treasury lock agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the unsettled interest rate swap derivatives that Avista Corp. has outstanding as of June 30, 2017 and December 31, 2016 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
June 30, 2017	6	$ 75,000	2017
	14	275,000	2018
	6	70,000	2019
	3	30,000	2020
	5	60,000	2022
December 31, 2016	6	$ 75,000	2017
	14	275,000	2018
	6	70,000	2019
	2	20,000	2020
	5	60,000	2022

The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. Avista Corp. is required to make cash payments to settle the interest rate swap derivatives when the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, Avista Corp. receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates. Upon settlement of interest rate swaps, the cash payments made or received are recorded as a regulatory asset or liability and are amortized as a component of interest expense over the life of the associated debt. The settled interest rate swaps are also included as a part of the Company's cost of debt calculation for ratemaking purposes.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Condensed Consolidated Balance Sheet as of June 30, 2017 and December 31, 2016 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of June 30, 2017 (in thousands):

	Fair Value as of June 30, 2017			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netted	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current assets	$ 187	$ —	$ —	$ 187
Interest rate swap derivatives				
Other current assets	5,626	(208)	—	5,418
Other property and investments-net and other non-current assets	5,676	(1,645)	—	4,031
Current interest rate swap derivative liabilities	—	(78,077)	41,570	(36,507)
Non-current interest rate swap derivative liabilities	—	(336)	—	(336)
Energy commodity derivatives				
Other current assets	168	(11)	—	157
Current energy commodity derivative liabilities	22,577	(36,716)	5,831	(8,308)
Other non-current liabilities, regulatory liabilities and deferred credits	12,532	(27,555)	3,936	(11,087)
Total derivative instruments recorded on the balance sheet	$ 46,766	$ (144,548)	$ 51,337	$ (46,445)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2016 (in thousands):

	Fair Value as of December 31, 2016			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netted	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current liabilities	$ 5	$ (28)	$ —	$ (23)
Interest rate swap derivatives				
Other current assets	3,393	—	—	3,393
Other property and investments-net and other non-current assets	5,754	(397)	—	5,357
Current interest rate swap derivative liabilities	—	(15,756)	9,731	(6,025)
Non-current interest rate swap derivative liabilities	3,951	(57,825)	25,169	(28,705)
Energy commodity derivatives				
Other current assets	18,682	(16,787)	—	1,895
Current energy commodity derivative liabilities	16,335	(29,598)	6,228	(7,035)
Other non-current liabilities, regulatory liabilities and deferred credits	13,071	(29,990)	3,630	(13,289)
Total derivative instruments recorded on the balance sheet	$ 61,191	$ (150,381)	$ 44,758	$ (44,432)

Exposure to Demands for Collateral

Avista Corp.'s derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement. In the event of a downgrade in Avista Corp.'s credit ratings or changes in market prices, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against Avista Corp.'s credit facilities and cash. Avista Corp. actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents Avista Corp.'s collateral outstanding related to its derivative instruments as of June 30, 2017 and December 31, 2016 (in thousands):

	June 30, 2017	December 31, 2016
Energy commodity derivatives		
Cash collateral posted	$ 15,924	$ 17,134
Letters of credit outstanding	37,250	24,400
Balance sheet offsetting (cash collateral against net derivative positions)	9,767	9,858
Interest rate swap derivatives		
Cash collateral posted	41,570	34,900
Letters of credit outstanding	13,100	3,600
Balance sheet offsetting (cash collateral against net derivative positions)	41,570	34,900

Certain of Avista Corp.'s derivative instruments contain provisions that require Avista Corp. to maintain an "investment grade" credit rating from the major credit rating agencies. If Avista Corp.'s credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions.

The following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position and the amount of additional collateral Avista Corp. could be required to post as of June 30, 2017 and December 31, 2016 (in thousands):

	June 30, 2017	December 31, 2016
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 648	$ 1,124
Additional collateral to post	648	1,046
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	80,266	73,978
Additional collateral to post	11,210	21,100

NOTE 4. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

Avista Utilities

Avista Utilities' pension and other postretirement plans have not changed during the six months ended June 30, 2017. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $14.8 million in cash to the pension plan for the six months ended June 30, 2017 and expects to contribute a total of $22.0 million in 2017. The Company contributed $12.0 million in cash to the pension plan in 2016.

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

	Pension Benefits		Other Post-retirement Benefits	
	2017	2016	2017	2016
Three months ended June 30:				
Service cost	$ 5,092	$ 4,569	$ 799	$ 804
Interest cost	6,976	6,900	1,374	1,534
Expected return on plan assets	(7,900)	(6,875)	(475)	(475)
Amortization of prior service cost	—	—	(312)	(312)
Net loss recognition	2,317	2,201	1,320	1,494
Net periodic benefit cost	$ 6,485	$ 6,795	$ 2,706	$ 3,045
Six months ended June 30:				
Service cost	$ 10,134	$ 9,088	$ 1,623	$ 1,583
Interest cost	13,927	13,800	2,773	3,093
Expected return on plan assets	(15,800)	(13,625)	(950)	(950)
Amortization of prior service cost	—	—	(624)	(624)
Net loss recognition	4,863	4,091	2,593	2,859
Net periodic benefit cost	$ 13,124	$ 13,354	$ 5,415	$ 5,961

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

NOTE 5. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million that expires in April 2021. The committed line of credit is secured by non-transferable first mortgage bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

Borrowings outstanding and interest rates of borrowings (excluding letters of credit) under the Company's revolving committed line of credit were as follows as of June 30, 2017 and December 31, 2016 (dollars in thousands):

	June 30, 2017	December 31, 2016
Borrowings outstanding at end of period	$ 136,000	$ 120,000
Letters of credit outstanding at end of period	$ 56,703	$ 34,353
Average interest rates at end of period	1.99%	1.50%

As of June 30, 2017 and December 31, 2016, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Condensed Consolidated Balance Sheet. The additional short-term borrowings outstanding as of June 30, 2017 on the Condensed Consolidated Balance Sheet relate to a short-term note payable by a subsidiary for the acquisition of land that will be repaid in early 2018.

AEL&P

AEL&P has a committed line of credit in the amount of $25.0 million that expires in November 2019. As of June 30, 2017 and December 31, 2016, there were no borrowings or letters of credit outstanding under this committed line of credit. The committed line of credit is secured by non-transferable first mortgage bonds of AEL&P issued to the agent bank that would only become due and payable in the event, and then only to the extent, that AEL&P defaults on its obligations under the committed line of credit.

NOTE 6. LONG-TERM DEBT AND CAPITAL LEASES

The following details long-term debt outstanding as of June 30, 2017 and December 31, 2016 (dollars in thousands):

Maturity Year	Description	Interest Rate	June 30, 2017	December 31, 2016
Avista Corp. Secured Long-Term Debt				
2018	First Mortgage Bonds	5.95%	$ 250,000	$ 250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds	4.11%	60,000	60,000
2045	First Mortgage Bonds	4.37%	100,000	100,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
2051	First Mortgage Bonds	3.54%	175,000	175,000
	Total Avista Corp. secured long-term debt		1,621,700	1,621,700
Alaska Electric Light and Power Company Secured Long-Term Debt				
2044	First Mortgage Bonds	4.54%	75,000	75,000
	Total secured long-term debt		1,696,700	1,696,700
Alaska Energy and Resources Company Unsecured Long-Term Debt				
2019	Unsecured Term Loan	3.85%	15,000	15,000
	Total secured and unsecured long-term debt		1,711,700	1,711,700
Other Long-Term Debt Components				
	Capital lease obligations		63,791	65,435
	Unamortized debt discount		(709)	(792)
	Unamortized long-term debt issuance costs		(10,204)	(10,639)
	Total		1,764,578	1,765,704
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt and capital leases		(277,814)	(3,287)
	Total long-term debt and capital leases		$ 1,403,064	$ 1,678,717

(1) In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new variable rate bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheets.

NOTE 7. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly.

The distribution rates paid were as follows during the six months ended June 30, 2017 and the year ended December 31, 2016:

	June 30, 2017	December 31, 2016
Low distribution rate	1.81%	1.29%
High distribution rate	2.08%	1.81%
Distribution rate at the end of the period	2.08%	1.81%

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II at any time and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed. The Company does not include these capital trusts in its consolidated financial statements as Avista Corp. is not the primary beneficiary. As such, the sole assets of the capital trusts are $51.5 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Condensed Consolidated Balance Sheets. Interest expense to affiliated trusts in the Condensed Consolidated Statements of Income represents interest expense on these debentures.

NOTE 8. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable, and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion and material capital leases) and long-term debt to affiliated trusts are reported at carrying value on the Condensed Consolidated Balance Sheets.

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

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

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

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

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

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

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Condensed Consolidated Balance Sheets as of June 30, 2017 and December 31, 2016 (dollars in thousands):

	June 30, 2017		December 31, 2016	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,076,925	$ 951,000	$ 1,048,661
Long-term debt (Level 3)	677,000	701,924	677,000	675,251
Snettisham capital lease obligation (Level 3)	60,953	62,600	62,160	62,800
Long-term debt to affiliated trusts (Level 3)	51,547	43,042	51,547	38,660

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 83.50 to 128.87, where a par value of 100.0 represents the carrying value recorded on the Condensed Consolidated Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds. Due to the unique nature of the Snettisham capital lease obligation, the estimated fair value of these items was determined based on a discounted cash flow model using available market information. The Snettisham capital lease obligation was discounted to present value using the Morgan Markets A Ex-Fin discount rate as published on June 30, 2017.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Condensed Consolidated Balance Sheets as of June 30, 2017 and December 31, 2016 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
June 30, 2017					
Assets:					
Energy commodity derivatives	$ —	$ 35,198	$ —	$ (35,041)	$ 157
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	79	(79)	—
Foreign currency exchange derivatives	—	187	—	—	187
Interest rate swap derivatives	—	11,302	—	(1,853)	9,449
Deferred compensation assets:					
Fixed income securities (2)	1,716	—	—	—	1,716
Equity securities (2)	6,067	—	—	—	6,067
Total	$ 7,783	$ 46,687	$ 79	$ (36,973)	$ 17,576
Liabilities:					
Energy commodity derivatives	$ —	$ 46,203	$ —	$ (44,808)	$ 1,395
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	4,252	(79)	4,173
Power exchange agreement	—	—	13,784	—	13,784
Power option agreement	—	—	43	—	43
Interest rate swap derivatives	—	80,266	—	(43,423)	36,843
Total	$ —	$ 126,469	$ 18,079	$ (88,310)	$ 56,238

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2016					
Assets:					
Energy commodity derivatives	$ —	$ 47,994	$ —	$ (46,099)	$ 1,895
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	69	(69)	—
Power exchange agreement	—	—	25	(25)	—
Foreign currency exchange derivatives	—	5	—	(5)	—
Interest rate swap derivatives	—	13,098	—	(4,348)	8,750
Deferred compensation assets:					
Fixed income securities (2)	1,789	—	—	—	1,789
Equity securities (2)	5,481	—	—	—	5,481
Total	$ 7,270	$ 61,097	$ 94	$ (50,546)	$ 17,915
Liabilities:					
Energy commodity derivatives	$ —	$ 56,871	$ —	$ (55,957)	$ 914
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	5,954	(69)	5,885
Power exchange agreement	—	—	13,474	(25)	13,449
Power option agreement	—	—	76	—	76
Foreign currency exchange derivatives	—	28	—	(5)	23
Interest rate swap derivatives	—	73,978	—	(39,248)	34,730
Total	$ —	$ 130,877	$ 19,504	$ (95,304)	$ 55,077

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists. In addition, the Company nets derivative assets and derivative liabilities against any payables and receivables for cash collateral held or placed with these same counterparties.
(2) These assets are trading securities and are included in other property and investments-net and other non-current assets on the Condensed Consolidated Balance Sheets.

The difference between the amount of derivative assets and liabilities disclosed in respective levels in the table above and the amount of derivative assets and liabilities disclosed on the Condensed Consolidated Balance Sheets is due to netting arrangements with certain counterparties. See Note 3 for additional discussion of derivative netting.

To establish fair value for energy commodity derivatives, the Company uses quoted market prices and forward price curves to estimate the fair value of energy commodity derivative instruments included in Level 2. In particular, electric derivative valuations are performed using market quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using market quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

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

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

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.2 million as of June 30, 2017 and $0.4 million as of December 31, 2016.

Level 3 Fair Value

Under the power exchange agreement the Company purchases power at a price that is based on the average operating and maintenance (O&M) charges from three surrogate nuclear power plants around the country. To estimate the fair value of this agreement the Company estimates the difference between the purchase price based on the future O&M charges and forward prices for energy. The Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average O&M charges from the three surrogate nuclear power plants for the current year. Because the nuclear power plant O&M charges are only known for one year, all forward years are estimated assuming an annual escalation. In addition to the forward price being estimated using unobservable inputs, the Company also estimates the volumes of the transactions that will take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, a change in the current year O&M charges for the surrogate plants is accompanied by a directionally similar change in O&M charges in future years. There is generally not a correlation between external market prices and the O&M charges used to develop the internal forward price.

For the power commodity option agreement, the Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include: 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges) and 2) estimated delivery volumes. Significant increases or decreases in these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices are accompanied by directionally similar changes in the strike price assumptions used in the calculation.

For the natural gas commodity exchange agreement, the Company uses the same Level 2 brokered quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions have not been highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of June 30, 2017 (dollars in thousands):

	Fair Value (Net) at June 30, 2017		Valuation Technique	Unobservable Input	Range
Power exchange agreement	$	(13,784)	Surrogate facility pricing	O&M charges	$33.59-$49.15/MWh (1)
				Escalation factor	3% - 2017 to 2019
				Transaction volumes	396,984 MWhs
Power option agreement	$	(43)	Black-Scholes-Merton	Strike price	$35.92/MWh - 2019
					$48.39/MWh - 2018
				Delivery volumes	128,611 - 254,363 MWhs
Natural gas exchange agreement	$	(4,173)	Internally derived weighted average cost of gas	Forward purchase prices	$1.66 - $2.38/mmBTU
				Forward sales prices	$1.67 - $3.29/mmBTU
				Purchase volumes	115,000 - 310,000 mmBTUs
				Sales volumes	60,000 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2016 are $39.22 per MWh. For ratemaking purposes the average O&M charges to be included for recovery in retail rates vary slightly between regulatory jurisdictions. The average O&M charges for the delivery year beginning in 2016 are $44.33 for Washington and $39.22 for Idaho.

The valuation methods, significant inputs and resulting fair values described above were developed by the Company's management and are reviewed on at least a quarterly basis to ensure they provide a reasonable estimate of fair value each reporting period.

The following table presents activity for energy commodity derivative assets (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the three and six months ended June 30 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Three months ended June 30, 2017:				
Balance as of April 1, 2017	$ (4,278)	$ (14,419)	$ (266)	$ (18,963)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	(195)	(672)	223	(644)
Settlements	300	1,307	—	1,607
Ending balance as of June 30, 2017 (2)	$ (4,173)	$ (13,784)	$ (43)	$ (18,000)
Three months ended June 30, 2016:				
Balance as of April 1, 2016	$ (6,006)	$ (20,193)	$ (97)	$ (26,296)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	(1,551)	4,400	(8)	2,841
Settlements	700	1,179	—	1,879
Ending balance as of June 30, 2016 (2)	$ (6,857)	$ (14,614)	$ (105)	$ (21,576)
Six months ended June 30, 2017:				
Balance as of January 1, 2017	$ (5,885)	$ (13,449)	$ (76)	$ (19,410)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	1,817	(5,165)	33	(3,315)
Settlements	(105)	4,830	—	4,725
Ending balance as of June 30, 2017 (2)	$ (4,173)	$ (13,784)	$ (43)	$ (18,000)
Six months ended June 30, 2016:				
Balance as of January 1, 2016	$ (5,039)	$ (21,961)	$ (124)	$ (27,124)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	(3,296)	1,968	19	(1,309)
Settlements	1,478	5,379	—	6,857
Ending balance as of June 30, 2016 (2)	$ (6,857)	$ (14,614)	$ (105)	$ (21,576)

(1) All gains and losses are included in other regulatory assets and liabilities. There were no gains and losses included in either net income or other comprehensive income during any of the periods presented in the table above.

(2) There were no purchases, issuances or transfers from other categories of any derivatives instruments during the periods presented in the table above.

NOTE 9. COMMON STOCK

In March 2016, the Company entered into four separate sales agency agreements under which Avista Corp.'s sales agents may offer and sell up to 3.8 million new shares of Avista Corp.'s common stock, no par value, from time to time. The sales agency agreements expire on February 29, 2020. As of June 30, 2017, 1.6 million shares have been issued under these agreements, leaving 2.2 million shares remaining to be issued. No shares were issued under these agreements in the six months ended June 30, 2017.

In the six months ended June 30, 2017, Avista Corp. issued 0.2 million shares of common stock, most of which were under employee incentive plans. The Company also issued a small number of shares under the 401(k) employee investment plan. Total net proceeds for all issuances were $1.2 million.

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

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

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Numerator:				
Net income attributable to Avista Corp. shareholders	$ 21,771	$ 27,254	$ 83,887	$ 84,903
Denominator:				
Weighted-average number of common shares outstanding-basic	64,401	63,386	64,382	62,995
Effect of dilutive securities:				
Performance and restricted stock awards	152	397	129	373
Weighted-average number of common shares outstanding-diluted	64,553	63,783	64,511	63,368
Earnings per common share attributable to Avista Corp. shareholders:				
Basic	$ 0.34	$ 0.43	$ 1.30	$ 1.35
Diluted	$ 0.34	$ 0.43	$ 1.30	$ 1.34

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

NOTE 11. COMMITMENTS AND CONTINGENCIES

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

California Refund Proceeding

In February 2016, APX, a market maker in the California Refund Proceedings in whose markets Avista Energy participated in the summer of 2000, asserted that Avista Energy and its other customer/participants may be responsible for a share of the disgorgement penalty APX may be found to owe to the California Parties (as defined in the 2016 Form 10-K). The penalty arises as a result of the Federal Energy and Regulatory Commission's (FERC) finding that APX committed violations in the California market in the summer of 2000. APX is making these assertions despite Avista Energy having been dismissed in FERC Opinion No. 536 from the on-going administrative proceeding at the FERC regarding potential wrongdoing in the California markets in the summer of 2000. APX has identified Avista Energy's share of APX's exposure to be as much as $16.0 million even though no wrongdoing allegations are specifically attributable to Avista Energy. Avista Energy believes its 2014 settlement with the California Parties insulates it from any such liability and that as a dismissed party it cannot be drawn back into the litigation. Avista Energy intends to vigorously dispute APX's assertions of indirect liability, but cannot at this time predict the eventual outcome.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels (referred to as "Total Dissolved Gas" or "TDG") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of Cabinet Gorge particularly during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement (CFSA) as incorporated in Avista Corp.'s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. Under the terms of a gas supersaturation mitigation plan, Avista is reducing TDG by constructing spill crest modifications on spill gates at the dam, and the Company expects to continue spill crest modifications over the next several years, in ongoing consultation with key stakeholders. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the United States Fish and Wildlife Service (USFWS) listed bull trout as threatened under the Endangered Species Act. In 2010, the USFWS issued a revised designation of critical habitat for bull trout, which includes the lower Clark Fork River. The USFWS issued a final recovery plan in October 2015.

The CFSA describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. Parties to the CFSA are working to resolve several issues. The Company believes its ongoing efforts through the CFSA continue to effectively address issues related to bull trout. Avista Corp. cannot at this time predict the outcome or estimate a range of costs associated with this contingency; however, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company's estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant. See "Note 19 of the Notes to Consolidated Financial Statements" in the 2016 Form 10-K for additional discussion regarding other contingencies.

NOTE 12. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss) attributable to Avista Corp. shareholders. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation; therefore, it is considered one segment. AEL&P is a separate reportable business segment as it has separate financial reports that are reviewed in detail by the Chief Operating Decision Maker and its operations and risks are sufficiently different from Avista Utilities and the other businesses at AERC that it cannot be aggregated with any other operating segments. The Other category, which is not a reportable segment, includes other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital.

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

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the three months ended June 30, 2017:						
Operating revenues	$ 296,747	$ 11,982	$ 308,729	$ 5,772	$ —	$ 314,501
Resource costs	99,461	3,290	102,751	—	—	102,751
Other operating expenses	78,970	2,995	81,965	7,086	—	89,051
Depreciation and amortization	41,195	1,448	42,643	157	—	42,800
Income (loss) from operations	53,971	3,597	57,568	(1,471)	—	56,097
Interest expense (2)	22,826	895	23,721	176	(27)	23,870
Income taxes	12,892	1,075	13,967	(916)	—	13,051
Net income (loss) attributable to Avista Corp. shareholders	21,765	1,681	23,446	(1,675)	—	21,771
Capital expenditures (3)	88,612	2,339	90,951	134	—	91,085

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the three months ended June 30, 2016:						
Operating revenues	$ 302,641	$ 10,247	$ 312,888	$ 5,950	$ —	$ 318,838
Resource costs	106,607	3,208	109,815	—	—	109,815
Other operating expenses	75,790	2,876	78,666	6,281	—	84,947
Depreciation and amortization	38,351	1,327	39,678	192	—	39,870
Income (loss) from operations	59,862	2,252	62,114	(523)	—	61,591
Interest expense (2)	20,462	895	21,357	149	(34)	21,472
Income taxes	16,349	676	17,025	(315)	—	16,710
Net income (loss) attributable to Avista Corp. shareholders	26,771	1,058	27,829	(575)	—	27,254
Capital expenditures (3)	88,048	5,889	93,937	46	—	93,983
For the six months ended June 30, 2017:						
Operating revenues	$ 712,128	$ 27,138	$ 739,266	$ 11,705	$ —	$ 750,971
Resource costs	262,074	6,263	268,337	—	—	268,337
Other operating expenses	150,682	5,767	156,449	13,265	—	169,714
Depreciation and amortization	81,733	2,895	84,628	345	—	84,973
Income (loss) from operations	162,606	10,782	173,388	(1,905)	—	171,483
Interest expense (2)	45,509	1,789	47,298	343	(41)	47,600
Income taxes	43,909	3,538	47,447	(1,052)	—	46,395
Net income (loss) attributable to Avista Corp. shareholders	80,204	5,534	85,738	(1,851)	—	83,887
Capital expenditures (3)	174,015	3,699	177,714	169	—	177,883
For the six months ended June 30, 2016:						
Operating revenues	$ 702,788	$ 22,893	$ 725,681	$ 11,330	$ —	$ 737,011
Resource costs	265,685	5,849	271,534	—	—	271,534
Other operating expenses	149,046	5,399	154,445	12,106	—	166,551
Depreciation and amortization	76,217	2,653	78,870	380	—	79,250
Income (loss) from operations	161,107	7,725	168,832	(1,156)	—	167,676
Interest expense (2)	40,880	1,790	42,670	310	(97)	42,883
Income taxes	45,021	2,571	47,592	(537)	—	47,055
Net income (loss) attributable to Avista Corp. shareholders	81,758	4,019	85,777	(874)	—	84,903
Capital expenditures (3)	172,483	10,332	182,815	165	—	182,980
Total Assets:						
As of June 30, 2017:	$ 5,034,778	$ 278,470	$ 5,313,248	$ 59,756	$ —	$ 5,373,004
As of December 31, 2016:	$ 4,975,555	$ 273,770	$ 5,249,325	$ 60,430	$ —	$ 5,309,755

(1) Intersegment eliminations reported as interest expense represent intercompany interest.
(2) Including interest expense to affiliated trusts.
(3) The capital expenditures for the other businesses are included in other investing activities on the Condensed Consolidated Statements of Cash Flows.

NOTE 13. SUBSEQUENT EVENT

On July 19, 2017, Avista Corp. entered into an Agreement and Plan of Merger (Merger Agreement), by and among Hydro One Limited (Hydro One), Olympus Holding Corp., a wholly owned subsidiary of Hydro One (US parent), and Olympus Corp., a wholly owned subsidiary of US parent (Merger Sub). Hydro One, based in Toronto, is Ontario's largest electricity transmission and distribution provider with more than 1.3 million customers, C$25.0 billion in assets and annual revenues of over C$6.5 billion.

The Merger Agreement provides for Avista Corp. to become an indirect, wholly-owned subsidiary of Hydro One. At the effective time of the merger, each share of Avista Corp. Common Stock issued and outstanding, other than Dissenting Shareholder Shares (as defined in the Merger Agreement) and shares of Avista Corp. Common Stock that are owned by Hydro One, US Parent or Merger Sub or any of their respective subsidiaries, will be converted automatically into the right to receive an amount in cash equal to $53.00, without interest.

Consummation of the merger is subject to the satisfaction or waiver of specified closing conditions, including, but not limited to, (i) the approval of the merger by the holders of a majority of the outstanding shares of Avista Corp. Common Stock, (ii) the receipt of regulatory approvals required to consummate the Merger, including approval from the FERC, the Committee on Foreign Investment in the United States (CFIUS), the Federal Communications Commission (FCC), the UTC, IPUC, Public Service Commission of the State of Montana (MPSC), OPUC, and the RCA, and (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. Avista Corp. expects to file for all necessary approvals within 45 to 60 days from the date of the Merger Agreement and the merger is expected to close during the second half of 2018.

The Merger Agreement also contains customary representations, warranties and covenants of Avista Corp., Hydro One, US Parent and Merger Sub. These covenants include, among others, an obligation on behalf of Avista Corp. to operate its business in the ordinary course until the Merger is consummated, subject to certain exceptions. In addition, the parties are required to use reasonable best efforts to obtain any required regulatory approvals.

Avista Corp. has made certain additional customary covenants, including, among others, and subject to certain exceptions, (a) causing a meeting of Avista Corp.'s shareholders to be held to consider approval of the Merger Agreement and (b) a customary non-solicitation covenant prohibiting Avista Corp. from soliciting, providing non-public information or entering into discussions or negotiations concerning proposals relating to alternative business combination transactions, except as and to the extent permitted under the Merger Agreement with respect to an unsolicited written Takeover Proposal (as defined in the Merger Agreement) made prior to the approval of the Merger by Avista Corp.'s shareholders if, among other things, Avista Corp.'s board of directors determines in good faith that such Takeover Proposal is or could be reasonably expected to lead to a Superior Proposal (as defined in the Merger Agreement) and that failure to take such actions would reasonably be expected to be inconsistent with its fiduciary duties under applicable law.

The Merger Agreement may be terminated by Avista Corp. and Hydro One by mutual consent and by either Avista Corp. or Hydro One under certain circumstances, including if the Merger is not consummated by September 30, 2018 (subject to an extension of up to six months by either party if all of the conditions to closing, other than the conditions related to obtaining required regulatory approvals, the absence of a law or injunction preventing the consummation of the Merger and the absence of a Burdensome Condition (as defined in the Merger Agreement) in any required regulatory approval, have been satisfied). The Merger Agreement also provides for certain additional termination rights for each of Avista Corp. and Hydro One. Upon termination of the Merger Agreement under certain specified circumstances, including (i) termination by Avista Corp. in order to enter into a definitive agreement with respect to a Superior Proposal, or (ii) termination by Hydro One following a withdrawal by Avista Corp.'s board or directors of its recommendation of the Merger Agreement, Avista Corp. will be required to pay Hydro One a termination fee of $103.0 million (Company Termination Fee). Avista Corp. will also be required to pay Hydro One the Company Termination Fee in the event Avista Corp. signs or consummates any specified alternative transaction within twelve months following the termination of the Merger Agreement under certain circumstances. In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain required regulatory approvals, the imposition of a Burdensome Condition with respect to a required regulatory approval, or the breach by Hydro One, US Parent or Merger Sub of their obligations in respect of obtaining regulatory approvals, Hydro One will be required to pay Avista Corp. a termination fee of $103.0 million.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have reviewed the accompanying condensed consolidated balance sheet of Avista Corporation and subsidiaries (the "Company") as of June 30, 2017, and the related condensed consolidated statements of income and comprehensive income for the three-month and six-month periods ended June 30, 2017 and 2016 and the related condensed consolidated statements of equity and cash flows for the six-month periods ended June 30, 2017 and 2016. These interim financial statements are the responsibility of the Company's management.

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

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

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Avista Corporation and subsidiaries as of December 31, 2016, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for the year then ended (not presented herein); and in our report dated February 21, 2017, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2016 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP

Seattle, Washington
August 1, 2017

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

Management's Discussion and Analysis of Financial Condition and Results of Operations has been prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q. The interim Management's Discussion and Analysis of Financial Condition and Results of Operations does not contain the full detail or analysis which would be included in a full fiscal year Form 10-K; therefore, it should be read in conjunction with the Company's 2016 Form 10-K.

Business Segments

Our business segments have not changed during the six months ended June 30, 2017. See the 2016 Form 10-K as well as "Note 12 of the Notes to Condensed Consolidated Financial Statements" for further information regarding our business segments.

The following table presents net income (loss) attributable to Avista Corp. shareholders for each of our business segments (and the other businesses) for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Avista Utilities	$ 21,765	$ 26,771	$ 80,204	$ 81,758
AEL&P	1,681	1,058	5,534	4,019
Other	(1,675)	(575)	(1,851)	(874)
Net income attributable to Avista Corp. shareholders	$ 21,771	$ 27,254	$ 83,887	$ 84,903

Executive Level Summary

Overall Results

Net income attributable to Avista Corp. shareholders was $21.8 million for the three months ended June 30, 2017, a decrease from $27.3 million for the three months ended June 30, 2016. Net income attributable to Avista Corp. shareholders was $83.9 million for the six months ended June 30, 2017, a decrease from $84.9 million for the six months ended June 30, 2016.

The decrease in earnings for both the second quarter and first half of 2017 was due to a decrease in earnings at Avista Utilities and an increase in losses at our other businesses, partially offset by an increase in earnings at AEL&P.

Avista Utilities' earnings decreased for both the second quarter and year-to-date 2017 due to an increase in other operating expenses, primarily due to an increase in generation, transmission and distribution maintenance costs, and increased depreciation and amortization and interest expense. As previously discussed, our 2016 requests for general rate increases in Washington were denied; therefore, we are not receiving regulatory recovery of the increase in expenses. In addition, there were also merger transaction costs incurred during the second quarter of 2017, which are not being passed through to customers. The increase in costs was partially offset by an increase in gross margin (operating revenues less resource costs) as a result of general rate increases in Idaho and Oregon, customer growth and lower electric resource costs. See "Results of Operations – Overall – Non-GAAP Financial Measures" for further discussion of gross margin.

AEL&P earnings increased for the second quarter and year-to-date 2017 primarily as a result of an increase in electric gross margin (operating revenues less resource costs), due to an interim general rate increase and higher loads due to colder weather in the first quarter, partially offset by an increase in operating expenses and a decrease in AFUDC and capitalized interest due to the construction of an additional back-up generation plant in 2016.

The increase in losses at our other businesses for both the second quarter and year-to-date 2017 was primarily related to renovation expenses and increased compliance costs at one of our subsidiaries and additional losses on investments as compared to 2016.

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

Recent Development

On July 19, 2017, Avista Corp. entered into a Merger Agreement that provides for Avista Corp. to become an indirect, wholly-owned subsidiary of Hydro One. Subject to the satisfaction or waiver of specified closing conditions, the merger is expected to close during the second half of 2018. At the effective time of the merger, each share of Avista Corp. Common Stock issued and outstanding other than Dissenting Shareholder Shares (as defined in the Merger Agreement) and shares of Avista Corp. Common Stock that are owned by Hydro One, US Parent or Merger Sub or any of their respective subsidiaries, will be converted automatically into the right to receive an amount in cash equal to $53.00, without interest. For further information, see "Note 13 of the Notes to Condensed Consolidated Financial Statements" and Avista Corp.'s Current Report on Form 8-K filed with the SEC on July 19, 2017.

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 expect to continue to file for rate adjustments to:

- seek recovery of operating costs and capital investments, and
- seek the opportunity to earn reasonable returns as allowed by regulators.

With regards to the timing and plans for future filings, the assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, but are not limited to, in-service dates of major capital investments and the timing of changes in major revenue and expense items.

Avista Utilities

Washington General Rate Cases

2015 General Rate Cases

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

The UTC-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 UTC also approved a rate of return (ROR) on rate base of 7.29 percent, with a common equity ratio of 48.5 percent and a 9.5 percent return on equity (ROE).

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

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

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

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

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

PC Petition for Judicial Review

On March 18, 2016, PC filed in Thurston County Superior Court a Petition for Judicial Review of the UTC's Order 05 and Order 06 described above that concluded our 2015 electric and natural gas general rate cases. In its Petition for Judicial Review, PC seeks judicial review of five aspects of Order 05 and Order 06, alleging, among other things, that (1) the UTC exceeded its statutory authority by setting rates for our natural gas and electric services based on amounts for utility plant and facilities that are not "used and useful" in providing utility service to customers; (2) the UTC acted arbitrarily and capriciously in granting an attrition adjustment for our electric operations after finding that the we did not meet the newly articulated standard regarding attrition adjustments; (3) the UTC erred in applying the "end results test" to set rates for our electric operations that are not supported by the record; (4) the UTC did not correct its calculation of our electric rates after significant errors were brought to its attention; and (5) the UTC's calculation of our electric rates lacks substantial evidence.

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

On April 18, 2016, PC filed an application with the Thurston County Superior Court to certify this matter for review directly by the Court of Appeals, an intermediate appellate court in the State of Washington. The matter was certified on April 29, 2016 and accepted by the Court of Appeals on July 29, 2016. The parties provide briefs to the Court, after which the Court will set the matter for argument. On July 7, 2017, ICNU filed a brief in support of PC. The UTC and Avista Corp. will respond on or before August 7, 2017. Oral argument has been set for September 12, 2017 before the court. A decision from the Court is not expected until late 2017, at the earliest.

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

The new rates established by Order 05 will continue in effect while the Petition for Judicial Review is being considered. We believe the UTC's Order 05 and Order 06 finalizing the electric and natural gas general rate cases provide a reasonable end result for all parties. If the outcome of the judicial review were to result in an electric rate reduction greater than the decrease ordered by the UTC, it may result in a refund liability to customers of up to $9.5 million, which is net of an approximately $2.5 million refund for Washington electric customers related to the 2016 provision for earnings sharing that we have already accrued.

2016 General Rate Cases

On December 15, 2016, the UTC issued an order related to our Washington electric and natural gas general rate cases that were originally filed with the UTC in February 2016. The UTC order denied the Company's proposed electric and natural gas rate increase requests of $38.6 million and $4.4 million, respectively. Accordingly, our current electric and natural gas retail rates remained unchanged in Washington State, following the order.

Our original requests were based on a proposed ROR of 7.64 percent with a common equity ratio of 48.5 percent and a 9.9 percent ROE.

On December 23, 2016 we filed a Petition for Reconsideration or, in the alternative, Rehearing (Petition) with the UTC related to our 2016 general rate cases. On February 27, 2017, we received an order from the UTC denying our Petition and confirming its previous order in the case. In its order denying the Petition, the UTC generally referred back to its prior findings and conclusions. See the 2016 Form 10-K for a detailed discussion surrounding UTC's prior findings and the information included in our Petition.

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

Following the conclusion of the 2016 case, we met with the Commissioners to better understand their concerns and their expectations going forward. The Company also met with members of the Commission Staff and other parties to discuss needs and expectations prior to filing the next general rate case. While these meetings with the Commissioners and Staff were constructive, there can be no assurance as to the outcome of any future general rate case.

2017 General Rate Cases

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

The two filings are summarized as follows:

Power Cost Rate Adjustment

The first filing is an electric only power cost rate adjustment that would update and reset power supply costs, effective September 1, 2017. We requested an overall increase in billed electric rates of 2.9 percent (designed to increase annual electric revenues by $15.0 million). The key drivers behind this request are related to the expiration of a capacity sales agreement with another utility and an increase in the price of natural gas to fuel our generating plants. Any new rates resulting from the power cost rate adjustment would expire upon the conclusion of the electric general rate case (discussed in further detail below), if approved.

On June 16, 2017, ICNU filed a Motion with the UTC to dismiss the power cost rate adjustment filing, or in the alternative, consolidate the filing with the pending general rate case filing. The UTC Staff and PC filed responses supporting ICNU's Motion. We expect the UTC to address the power cost rate adjustment by August 10, 2017, at which time they will either approve or deny the request or indicate additional steps that may be necessary.

General Rate Requests

The second request relates to electric and natural gas general rate cases. We filed three-year rate plans for electric and natural gas and have requested the following for each year (dollars in millions):

	Electric		Natural Gas	
Effective Date	Proposed Revenue Increase	Proposed Base Rate Increase	Proposed Revenue Increase	Proposed Base Rate Increase
May 1, 2018 (1)	$ 61.4	12.5%	$ 8.3	9.3%
May 1, 2019 (2)	$ 14.0	2.5%	$ 4.2	4.4%
May 1, 2020 (2)	$ 14.4	2.5%	$ 4.4	4.4%

(1) The $61.4 million electric revenue increase includes the $15.0 million power cost rate adjustment discussed above.

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

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

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

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

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

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

AMI Project in Washington State

In March 2016, the UTC granted our Petition for an Accounting Order to defer and include in a regulatory asset the undepreciated value of our existing Washington electric meters for the opportunity for later recovery. This accounting treatment is related to our plans to replace approximately 253,000 of our existing electric meters with new two-way digital meters and the related software and support services through our AMI project in Washington State. Replacement of the meters is expected to begin in the second half of 2018. As of June 30, 2017, the estimated undepreciated value for the existing meters is $19.8 million.

In April 2017, we identified approximately 70,000 natural gas encoder receiver transmitters (ERTs) that will need to be replaced as part of the AMI project. In May 2017, we filed a Petition with the UTC requesting deferred accounting treatment for the investment costs associated with the Washington AMI project, including components such as meter communication networks, information management systems and the natural gas ERTs. The Petition requests the deferral and inclusion in a regulatory asset of all AMI investment costs over the multi-year implementation period, until the costs can be reviewed for prudence in a future regulatory proceeding and recovered in retail rates. The undepreciated value of the natural gas ERTS is approximately $3.7 million.

Idaho General Rate Cases

2016 General Rate Case

In December 2016, the IPUC approved a settlement agreement between us and other parties in our electric general rate case, concluding our Idaho electric general rate case originally filed in May 2016. New rates took effect on January 1, 2017 under the settlement agreement. 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 revenue increase is based on a ROR of 7.58 percent with a common equity ratio of 50 percent and a 9.5 percent ROE.

In addition to the agreed upon increase in electric revenues to recover costs primarily driven by our increased capital investments in infrastructure to serve customers, the settlement agreement includes the continued recovery of approximately $4.1 million in costs related to the Palouse Wind Project through the Power Cost Adjustment (PCA) mechanism rather than through base rates.

In our original request we requested an overall increase in base electric rates of 6.3 percent (designed to increase annual electric revenues by $15.4 million), effective January 1, 2017.

Our original request was based on a proposed ROR of 7.78 percent with a common equity ratio of 50 percent and a 9.9 percent ROE.

2017 General Rate Cases

On June 9, 2017, we filed electric and natural gas general rate requests with the IPUC to recover increased power supply costs and capital investments made since the last determination of our rate base in the 2016 Idaho electric general rate case and the 2015 Idaho natural gas general rate case.

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

	Electric		Natural Gas	
Effective Date	Proposed Revenue Increase	Proposed Base Rate Increase	Proposed Revenue Increase	Proposed Base Rate Increase
January 1, 2018	$ 18.6	7.5%	$ 3.5	8.8%
January 1, 2019 (1)	$ 9.9	3.7%	$ 2.1	5.0%

(1) We are not proposing to update base power supply costs for year two of the rate plan, but rather have any differences flow through the PCA mechanism.

Our requests are based on a proposed ROR of 7.81 percent with a common equity ratio of 50.0 percent and a 9.9 percent ROE.

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

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

- Generator maintenance at the Kettle Falls biomass plant that will ensure efficient generation and operations.
- The ongoing project to systematically replace portions of natural gas distribution pipe in our service area that were installed prior to 1987, as well as replacement of other natural gas service equipment.

- Transmission and distribution system and asset maintenance, such as wood pole replacements, feeder upgrades, and substation and transmission line rebuilds to maintain reliability for our customers.
- Technology upgrades that support necessary business processes and operational efficiencies that allow us to effectively manage the utility and serve customers.
- A refresh of the customer-facing website, providing relevant information, greater accessibility on mobile devices, easier navigation, and a streamlined payment experience.

A procedural schedule has been agreed to by the parties in the case, and recommended to the IPUC, which would result in an IPUC decision on or before January 1, 2018.

Oregon General Rate Cases

2015 General Rate Case

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

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

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

2016 General Rate Case

On May 16, 2017, an all-party settlement agreement was filed with the OPUC, which, if approved by the OPUC, would resolve all issues in the case and new rates would take effect on October 1, 2017.

The settlement proposes that, effective October 1, 2017, we would receive an increase in rates designed to increase annual base revenues by 5.9 percent or $3.5 million. In addition, in the settlement agreement, we agreed to non-recovery of certain utility plant expenditures, which resulted in a write-off of approximately $0.8 million in the second quarter of 2017.

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

Alaska Electric Light and Power Company

Alaska General Rate Case

In September 2016, AEL&P filed an electric general rate case with the RCA. AEL&P was granted a refundable interim base rate increase of 3.86 percent (designed to increase electric revenues by $1.3 million), which took effect in November 2016. AEL&P has also requested a permanent base rate increase of an additional 4.24 percent (designed to increase electric revenues by $1.5 million), which, if approved, could take effect in February 2018. This represents a combined total rate increase of 8.1 percent (designed to increase electric revenues by $2.8 million).

Included in the general rate case are additional annual revenues of $2.9 million from the Greens Creek Mine, which offsets a portion of the rate increase to retail customers that would otherwise occur.

The RCA must rule on permanent rate increase requests within 450 days (approximately 15 months) from the date of filing, unless otherwise extended by consent of the parties. The timeline for the AEL&P general rate case, with the consent of the parties, was extended to February 8, 2018.

The rate request is based largely on the addition of a new backup generation plant (Industrial Blvd. Plant) to rate base.

Avista Utilities

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to Avista Utilities' customers with no change in gross margin or net income. In Oregon, we absorb (cost or benefit) 10 percent of the difference between actual and projected gas costs included in retail rates for supply that is not hedged. Total net deferred natural gas costs among all jurisdictions were a liability of $29.0 million as of June 30, 2017 and a liability of $30.8 million as of December 31, 2016. These balances represent amounts due to customers.

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between Avista Utilities' actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers and defer these differences (over the $4.0 million deadband and sharing bands) for future surcharge or rebate to customers. See the 2016 Form 10-K for a full discussion of the mechanics of the ERM and the various sharing bands. Total net deferred power costs under the ERM was a liability of $23.5 million as of June 30, 2017, compared to a liability of $21.3 million as of December 31, 2016. These deferred power cost balances represent amounts due to customers.

Avista Utilities has a PCA mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers for future surcharge or rebate to customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $7.4 million as of June 30, 2017 and a liability of $2.2 million as of December 31, 2016. These deferred power cost balances represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

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

Washington Decoupling and Earnings Sharing Mechanisms

In Washington, the UTC approved our decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations are made for the calendar year just ended. These earnings tests reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. The operation of the Washington decoupling and earnings sharing mechanisms has not changed for the six months ended June 30, 2017. These decoupling and earnings sharing mechanisms are more fully described in the 2016 Form 10-K. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Idaho Fixed Cost Adjustment (FCA) and Earnings Sharing Mechanisms

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

For the period 2013 through 2015, we had an after-the-fact earnings test such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earned more than a 9.8 percent ROE, we were required to share with customers 50 percent of any earnings above the 9.8 percent. This after-the-fact earnings test was discontinued, effective January 1, 2016, as part of the settlement of our 2015 Idaho electric and natural gas general rates cases. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Oregon Decoupling Mechanism

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

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of June 30, 2017 and December 31, 2016, we had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in our various jurisdictions (dollars in thousands):

	June 30, 2017	December 31, 2016
Washington		
Decoupling surcharge	$ 24,031	$ 30,408
Provision for earnings sharing rebate	(5,860)	(5,113)
Idaho		
Decoupling surcharge	$ 6,345	$ 8,292
Provision for earnings sharing rebate	(3,731)	(5,184)
Oregon		
Decoupling surcharge (rebate)	$ (19)	$ 2,021

See "Results of Operations - Avista Utilities" for further discussion of the amounts recorded to operating revenues in 2017 and 2016 related to the decoupling and earnings sharing mechanisms.

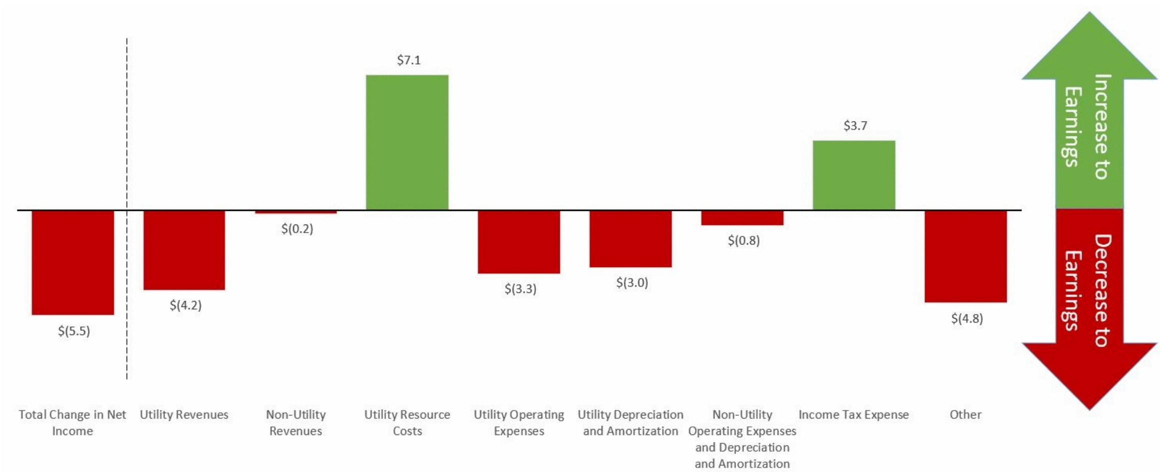
Results of Operations - Overall

The following provides an overview of changes in our Condensed Consolidated Statements of Income. More detailed explanations are provided, 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 Condensed Consolidated Statements of Income.

Three months ended June 30, 2017 compared to the three months ended June 30, 2016

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



Utility revenues decreased due to a decrease at Avista Utilities, partially offset by an increase at AEL&P. Avista Utilities' revenues decreased primarily due to a decrease in electric and natural gas wholesale sales and a change in the electric provision for earnings sharing. These revenue decreases were partially offset by an electric general rate increase in Idaho, a natural gas general rate increase in Oregon and higher retail electric and natural gas heating loads due to customer growth and weather that was cooler than the prior year. There were electric decoupling surcharges during both the second quarter of 2017 and 2016 and natural gas decoupling surcharges during the second quarter of 2016, but there was a natural gas decoupling rebate during the second quarter of 2017. The surcharges were larger in 2016 because weather was warmer than normal during that period. 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.

Utility resource costs decreased due to a decrease at Avista Utilities, partially offset by a slight increase at AEL&P. Avista

Utilities' electric resource costs decreased due to a decrease in purchased power, resulting from a decrease in volumes and a decrease in wholesale prices, as well as a decrease in fuel for generation resulting from higher hydroelectric generation and lower thermal generation.

The increase in utility other operating expenses was due to an increase at Avista Utilities and a slight increase at AEL&P. The increase at Avista Utilities' was the result of an increase in generation, transmission and distribution maintenance costs, as well as a write-off in Oregon of utility plant associated with a general rate case settlement. There were also merger transaction costs incurred during the second quarter of 2017, which are not being passed through to customers. The increased costs were partially offset by decreases in pension, other postretirement benefit and medical expenses.

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

Non-utility other operating expenses increased primarily due to renovation expenses and increased compliance costs at one of our subsidiaries.

Income taxes decreased due to a decrease in income before income taxes. Our effective tax rate was 37.5 percent for the second quarter of 2017 compared to 38.0 percent for the second quarter of 2016.

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. Also, there was an increase in utility taxes other than income taxes primarily due to revenue related taxes and property taxes. Lastly, there was an increase in losses on investments at our subsidiaries.

Six months ended June 30, 2017 compared to the six months ended June 30, 2016

The following graph shows the total change in net income attributable to Avista Corp. shareholders for the six months ended June 30, 2016 to the six months ended June 30, 2017, as well as the various factors that caused such change (dollars in millions):

Utility revenues increased due to increases at both Avista Utilities and AEL&P. Avista Utilities' revenues increased primarily due to an electric general rate increase in Idaho, a natural gas general rate increase in Oregon and higher retail electric and natural gas heating loads due to customer growth and weather that was cooler than the prior year. The increased utility revenues were partially offset by decoupling rebates in the first half of 2017 due to weather that was cooler than normal. This compares to decoupling surcharges during the first half of 2016. These increases were partially offset by a change in the electric provision for earnings sharing, which increased revenue during 2016 (due to a reduction to the 2015 provisions in Washington and Idaho recorded in 2016). 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.

Utility resource costs decreased due to a decrease at Avista Utilities, partially offset by a slight increase at AEL&P. Avista Utilities' electric resource costs decreased due to a decrease in purchased power, resulting from a decrease in wholesale prices, partially offset by an increase in volumes, and a decrease in fuel for generation resulting from higher hydroelectric generation and lower thermal generation.

The increase in utility other operating expenses was due to an increase at Avista Utilities and a slight increase at AEL&P. The increase at Avista Utilities' was the result of an increase in generation, transmission and distribution maintenance costs, as well as a write-off in Oregon of utility plant associated with a general rate case settlement. There were also merger transaction costs incurred during the second quarter of 2017, which are not being passed through to customers. The increased costs were partially offset by decreases in pension, other postretirement benefit and medical expenses.

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

Non-utility other operating expenses increased primarily due to renovation expenses and increased compliance costs at one of our subsidiaries.

Income taxes decreased primarily due to a decrease in income before income taxes. Our effective tax rate was 35.6 percent for the first six months of 2017 and 2016.

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. Also, there was an increase in utility taxes other than income taxes primarily due to revenue related taxes and property taxes. Lastly, there was an increase in losses on investments at our subsidiaries.

Non-GAAP Financial Measures

The following discussion for Avista Utilities includes two financial measures that are considered “non-GAAP financial measures,” electric gross margin and natural gas gross margin. In the AEL&P section, we include a discussion of electric gross margin, which is also a non-GAAP financial measure.

Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included (excluded) in the most directly comparable measure calculated and presented in accordance with GAAP. The presentation of electric gross margin and natural gas gross margin is intended to supplement an understanding of operating performance. We use these measures to determine whether the appropriate amount of revenue is being collected from our customers to allow for the recovery of energy resource costs and operating costs, as well as to analyze how changes in loads (due to weather, economic or other conditions), rates, supply costs and other factors impact our results of operations. In addition, we present electric and natural gas gross margin separately below for Avista Utilities since each business has different cost sources, cost recovery mechanisms and jurisdictions, such that separate analysis is beneficial. These measures are not intended to replace income from operations as determined in accordance with GAAP as an indicator of operating performance. The calculations of electric and natural gas gross margins are presented below.

Results of Operations - Avista Utilities

Three months ended June 30, 2017 compared to the three months ended June 30, 2016

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

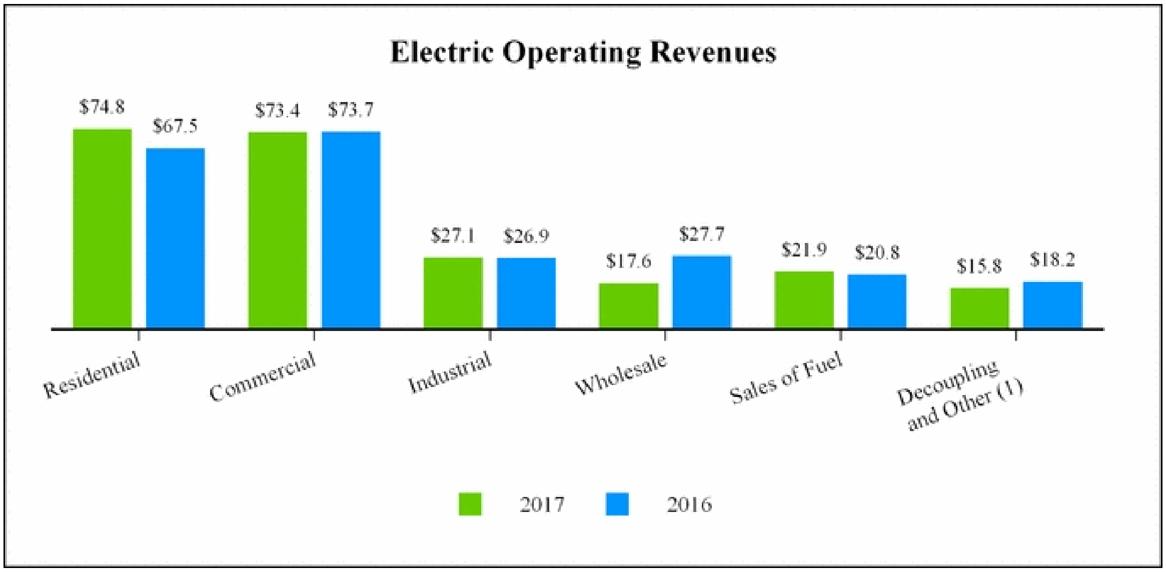
	Electric		Natural Gas		Intracompany		Total	
	2017	2016	2017	2016	2017	2016	2017	2016
Operating revenues	$ 230,558	$ 234,791	$ 80,430	$ 80,955	$ (14,241)	$ (13,105)	$ 296,747	$ 302,641
Resource costs	69,427	73,350	44,275	46,362	(14,241)	(13,105)	99,461	106,607
Gross margin	$ 161,131	$ 161,441	$ 36,155	$ 34,593	$ —	$ —	$ 197,286	$ 196,034

The gross margin on electric sales decreased $0.3 million and the gross margin on natural gas sales increased $1.6 million in the second quarter of 2017 compared to the second quarter of 2016. The slight decrease in electric gross margin was primarily due to a change in the provision for earnings sharing (which reduced electric gross margin by $2.0 million for 2017 as compared to 2016), mostly offset by a general rate increase in Idaho, customer growth and lower resource costs. For the second quarter of 2017, we had a $0.6 million pre-tax benefit under the ERM in Washington, compared to a $0.2 million pre-tax expense for the second quarter of 2016. For the full year of 2017, we expect to be in an expense position under the ERM within the $4 million deadband because power supply costs were not reset for 2017 since our 2016 request for a general electric rate increase in Washington was denied. If power supply costs are reset in our Power Cost Rate Adjustment request, we would expect to be in a benefit position under the ERM within the $4 million deadband for the full year of 2017. See further discussion of the Washington order in "Item 2. Management's Discussion and Analysis – Regulatory Matters."

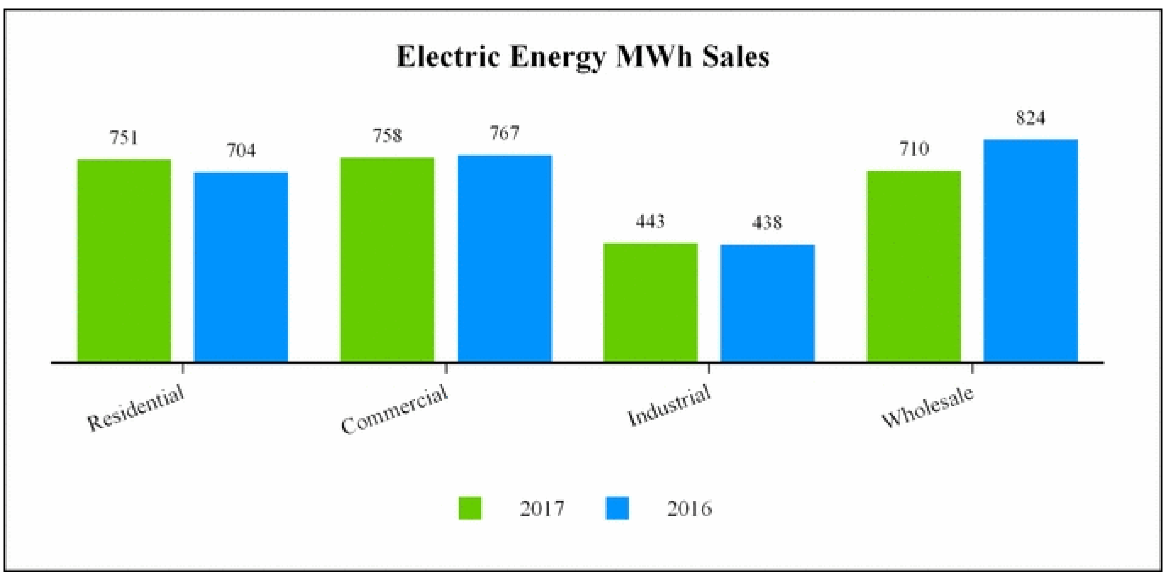
The increase in natural gas gross margin was primarily due to a general rate increase in Oregon and customer growth.

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

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



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



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

	Electric Operating Revenues	
	2017	2016
Washington		
Decoupling surcharge	$ 3,661	$ 4,553
Provision for earnings sharing (1)	(130)	1,119
Idaho		
Decoupling surcharge	$ 862	$ 2,651
Provision for earnings sharing (2)	n/a	711

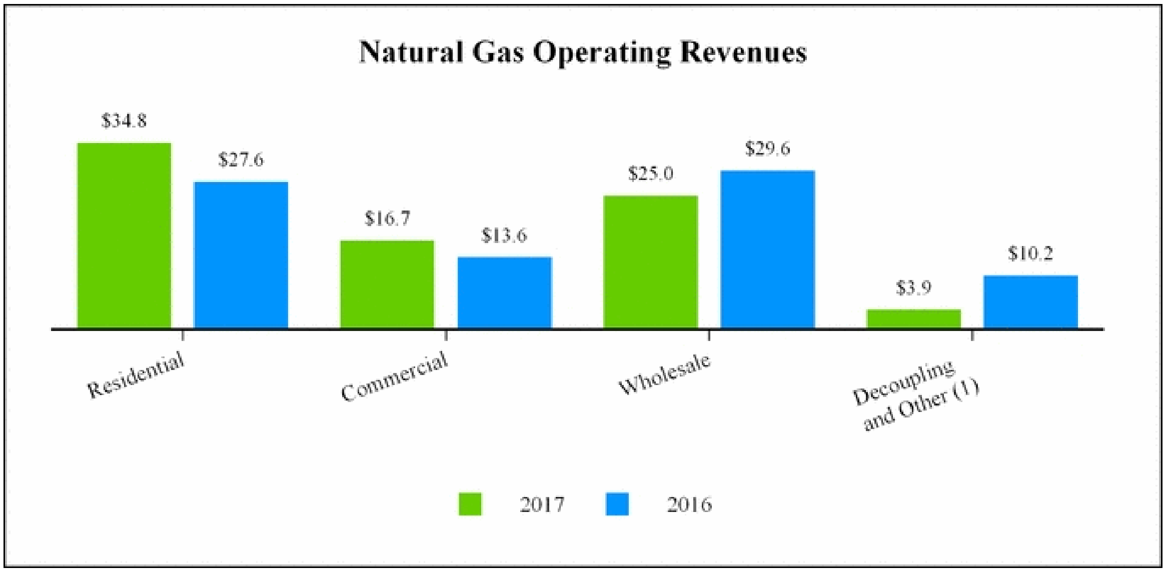
(1) The provision for earnings sharing in Washington for the second quarter of 2017 represents an adjustment of the 2016 provision for earnings sharing. We are not expecting a provision for earnings sharing in Washington relating to 2017 earnings. The provision for earnings sharing in Washington in the second quarter of 2016 resulted from a $1.2 million reduction in the 2015 provision for earnings sharing (which increased 2016 revenues), partially offset by a $0.1 million provision for the second quarter of 2016.

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

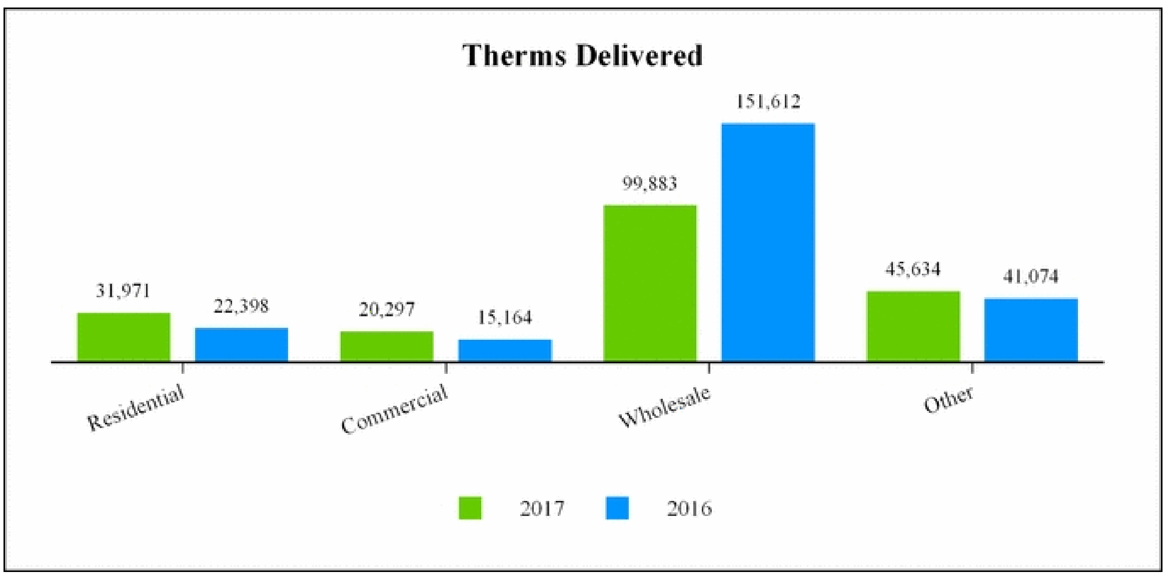
Total electric revenues decreased $4.2 million for the second quarter of 2017 as compared to the second quarter of 2016 primarily reflecting the following:

- a $7.0 million increase in retail electric revenue due to an increase in total MWhs sold (increased revenues $3.8 million) and an increase in revenue per MWh (increased revenues $3.2 million).
    - The increase in total retail MWhs sold was the result of weather that was cooler than the prior year (which increased electric heating loads, partially offset by a decrease in cooling loads), as well as customer growth. Compared to the second quarter of 2016, residential electric use per customer increased 6 percent and commercial use per customer decreased 2 percent. Heating degree days in Spokane were 12 percent below normal, but 45 percent above the second quarter of 2016. Cooling degree days in Spokane were 54 percent above normal, but 12 percent below the second quarter of 2016.
    - 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 the second quarter of 2017.
- a $10.1 million decrease in wholesale electric revenues due to a decrease in sales prices (decreased revenues $7.2 million) and a decrease in sales volumes (decreased revenues $2.9 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $1.1 million increase in sales of fuel due to an increase in sales of natural gas fuel as part of thermal generation resource optimization activities. For the second quarter of 2017, $5.3 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the second quarter of 2016, $8.0 million of these sales were made to our natural gas operations.
- a $2.7 million decrease in electric revenue due to decoupling. Weather was generally warmer than normal in both periods, which resulted in decoupling surcharges for both the second quarter of 2017 and 2016; however, the surcharges were larger during 2016 since the weather differed more from normal in 2016 than it did in 2017. Decoupling mechanisms are not impacted by fluctuations in weather compared to prior year, they are only impacted by weather fluctuations as compared to normal weather.

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



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

	Natural Gas Operating Revenues	
	2017	2016
Washington		
Decoupling surcharge	$ 30	$ 3,595
Provision for earnings sharing	(617)	(320)
Idaho		
Decoupling surcharge (rebate)	$ (106)	$ 589
Oregon		
Decoupling surcharge (rebate)	$ (121)	$ 1,690

Total natural gas revenues decreased $0.5 million for the second quarter of 2017 as compared to the second quarter of 2016 primarily reflecting the following:

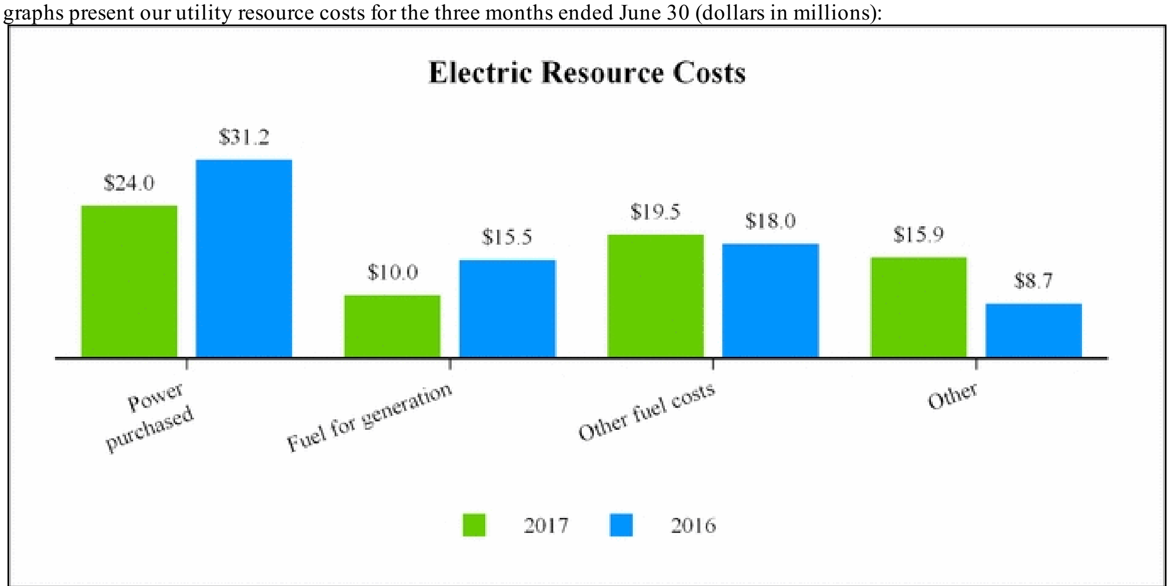
- a $10.3 million increase in natural gas retail revenues due an increase in volumes (increased revenues $14.4 million), partially offset by lower retail rates (decreased revenues $4.1 million).
  - We sold more retail natural gas in the second quarter of 2017 as compared to the second quarter of 2016 due to weather that was cooler than the prior year. Compared to the second quarter of 2016, residential natural gas use per customer increased 39 percent and commercial use per customer increased 33 percent. Heating degree days in Spokane were 12 percent below normal, but 45 percent above the second quarter of 2016. Heating degree days in Medford were 11 percent below normal, but 60 percent above the second quarter of 2016.
  - Lower retail rates were due to PGAs, partially offset by a general rate increase in Oregon.
- a $4.7 million decrease in wholesale natural gas revenues due to a decrease in volumes (decreased revenues $13.0 million), partially offset by an increase in market prices (increased revenues $8.3 million). In the second quarter of 2017, $9.0 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the second quarter of 2016, $5.1 million of these sales were made to our electric generation operations. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.
- a $6.1 million decrease in natural gas revenue due to decoupling. Weather was generally warmer than normal during the second quarter 2017; however, due to the shape of the normal usage curve for natural gas in the decoupling mechanism, this resulted in a small rebate during the second quarter in Idaho and Oregon and a small net surcharge in Washington. This compares to significant decoupling surcharges in the second quarter of 2016. Decoupling mechanisms are not impacted by fluctuations in weather compared to prior year, they are only impacted by weather fluctuations as compared to normal weather.

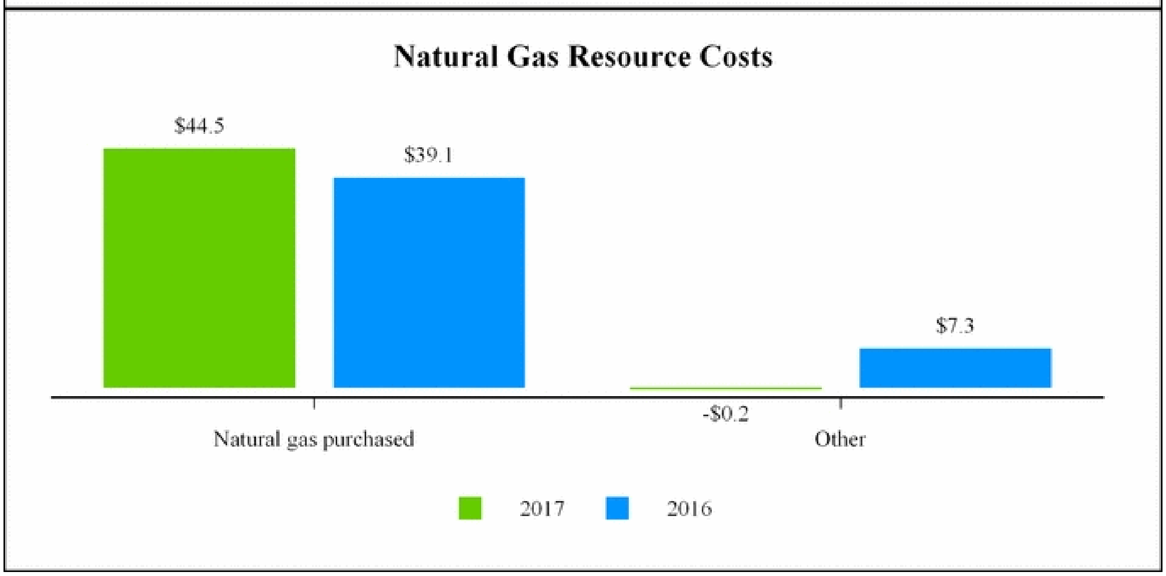
The following table presents our average number of electric and natural gas retail customers for the three months ended June 30:

	Electric Customers		Natural Gas Customers	
	2017	2016	2017	2016
Residential	333,465	329,551	306,238	299,860
Commercial	42,074	41,732	35,197	34,867
Interruptible	—	—	38	37
Industrial (1)	1,328	1,346	250	255
Public street and highway lighting	558	559	—	—
Total retail customers	377,425	373,188	341,723	335,019

(1) The decrease in electric industrial customers as compared to the second quarter of 2016 is primarily related to a decrease in Washington irrigation customers.

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





Total resource costs in the graphs above include intracompany resource costs of $14.2 million and $13.1 million for the three months ended June 30, 2017 and June 30, 2016, respectively.

Total electric resource costs decreased $3.9 million for the second quarter of 2017 as compared to the second quarter of 2016 reflecting the following:

- a $7.3 million decrease in purchased power due to a decrease in the volume of power purchases (decreased costs $1.1 million) and a decrease in wholesale prices (decreased costs $6.2 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the quarter.
- a $5.5 million decrease in fuel for generation primarily due to a decrease in thermal generation (due in part to increased hydroelectric generation).
- a $1.5 million increase in other fuel costs. This represents fuel and the related derivative instruments that were purchased for generation but were later sold when conditions indicated that it was more economical to sell the fuel as

part of the resource optimization process. When the fuel or related derivative instruments are sold, that revenue is included in sales of fuel.

- a $7.0 million increase from amortizations and deferrals of power costs. This change was primarily to result of lower net power supply costs.
- a $0.2 million net increase from other regulatory amortizations and other electric resource costs.

Total natural gas resource costs decreased $2.1 million for the second quarter of 2017 as compared to the second quarter of 2016 reflecting the following:

- a $5.4 million increase in natural gas purchased due to an increase in the market price of natural gas (increased costs $16.0 million), partially offset by a decrease in total therms purchased (decreased costs $10.6 million). Total therms purchased decreased due to a decrease in wholesale sales, partially offset by an increase in retail sales.
- a $0.8 million increase in other regulatory amortizations.
- an $8.3 million decrease from amortizations and deferrals of natural gas costs. This reflects lower natural gas prices compared to our authorized PGA rates and the deferral of these lower costs, which occurred in the current quarter for future rebate to customers.

Six months ended June 30, 2017 compared to the six months ended June 30, 2016

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

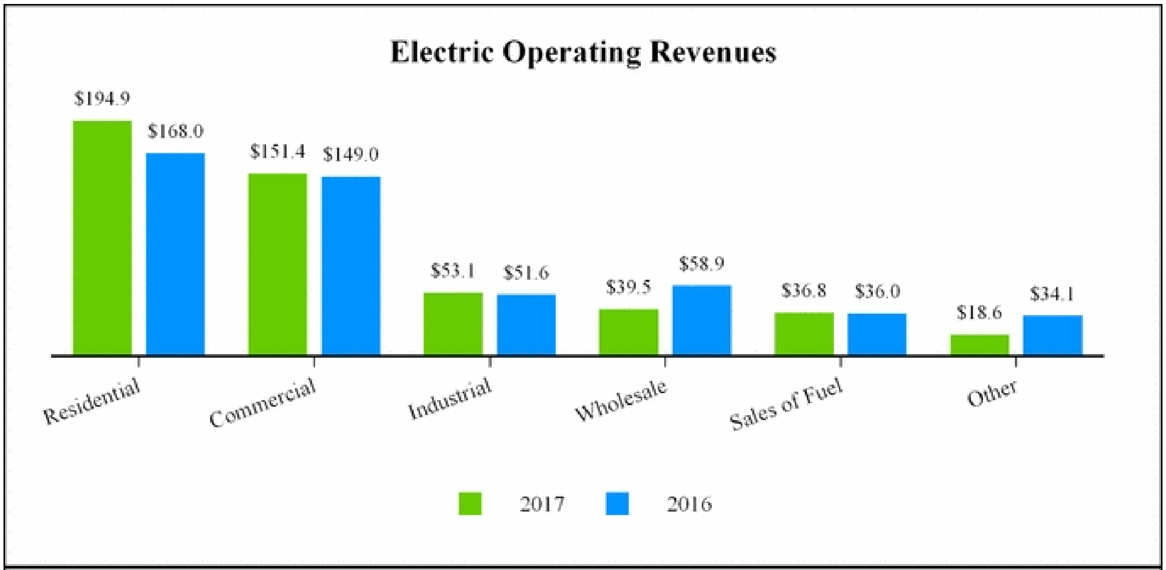
	Electric		Natural Gas		Intracompany		Total	
	2017	2016	2017	2016	2017	2016	2017	2016
Operating revenues	$ 494,276	$ 497,593	$ 250,642	$ 236,365	$ (32,790)	$ (31,170)	$ 712,128	$ 702,788
Resource costs	160,302	167,702	134,562	129,153	(32,790)	(31,170)	262,074	265,685
Gross margin	$ 333,974	$ 329,891	$ 116,080	$ 107,212	$ —	$ —	$ 450,054	$ 437,103

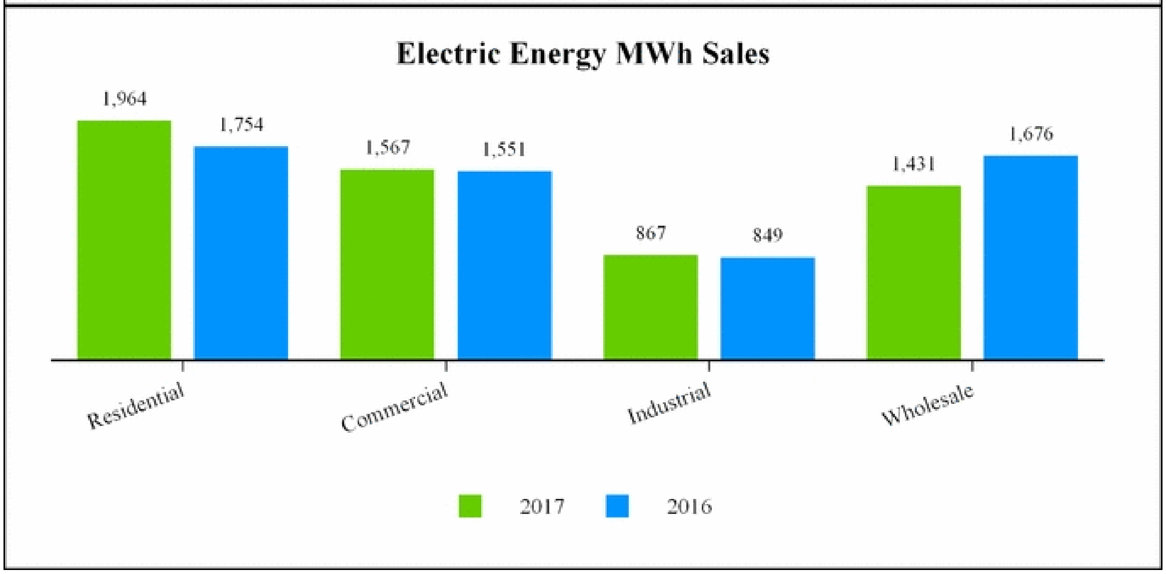
The gross margin on electric sales increased $4.1 million and the gross margin on natural gas sales increased $8.9 million. The increase in electric gross margin was primarily due to a general rate increase in Idaho, customer growth and lower resource costs, partially offset by a change in the provision for earnings sharing (which reduced electric gross margin by $3.0 million for 2017 as compared to 2016). For the six months ended June 30, 2017, we recognized a pre-tax benefit of $4.6 million under the ERM in Washington compared to a benefit of $4.2 million for the six months ended June 30, 2016.

The increase in natural gas gross margin was primarily due to a general rate increase in Oregon and 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 condensed consolidated financial statements but are included in the separate results for electric and natural gas presented below.

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





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

	Electric Operating Revenues	
	2017	2016
Washington		
Decoupling surcharge (rebate)	$ (1,461)	$ 8,634
Provision for earnings sharing (1)	(130)	2,169
Idaho		
Decoupling surcharge (rebate)	$ (1,096)	$ 5,031
Provision for earnings sharing (2)	n/a	711

(1) The provision for earnings sharing in Washington for the six months ended June 30, 2017 represents an adjustment of the 2016 provision for earnings sharing. We are not expecting a provision for earnings sharing in Washington relating to 2017 earnings. The provision for earnings sharing in Washington in the six months ended June 30, 2016 resulted from a $2.5 million reduction in the 2015 provision for earnings sharing (which increased 2016 revenues), partially offset by $0.3 million provision for the six months ended June 30, 2016.

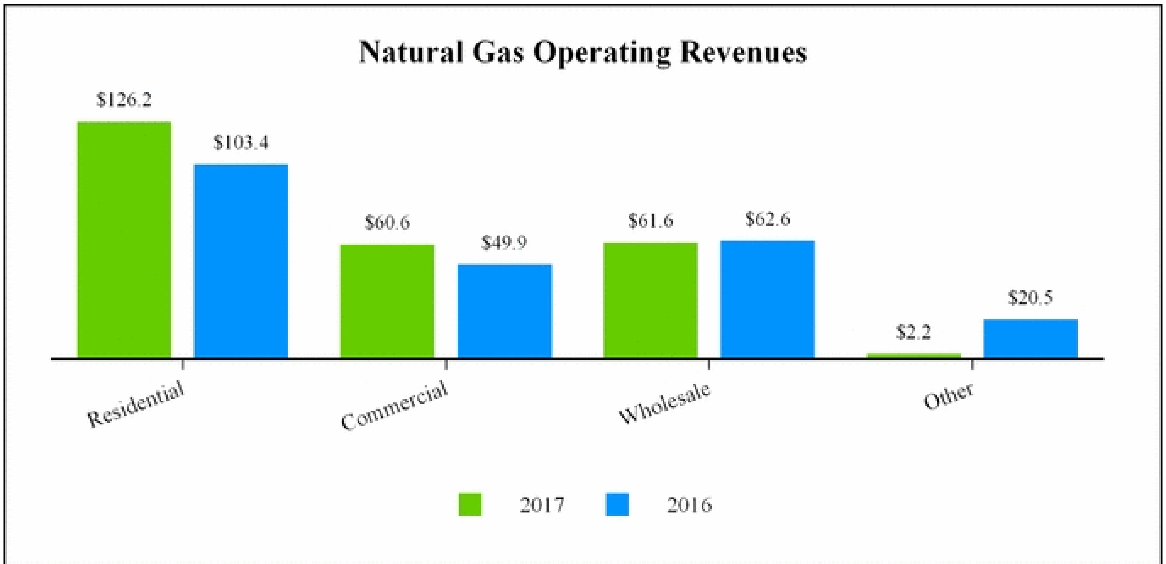
(2) The provision for earnings sharing in Idaho in the six months ended June 30, 2016 resulted from a reduction in the 2015 provision for earnings sharing (which increased 2016 revenues). Beginning in 2016 there is no longer an earnings sharing mechanism in Idaho.

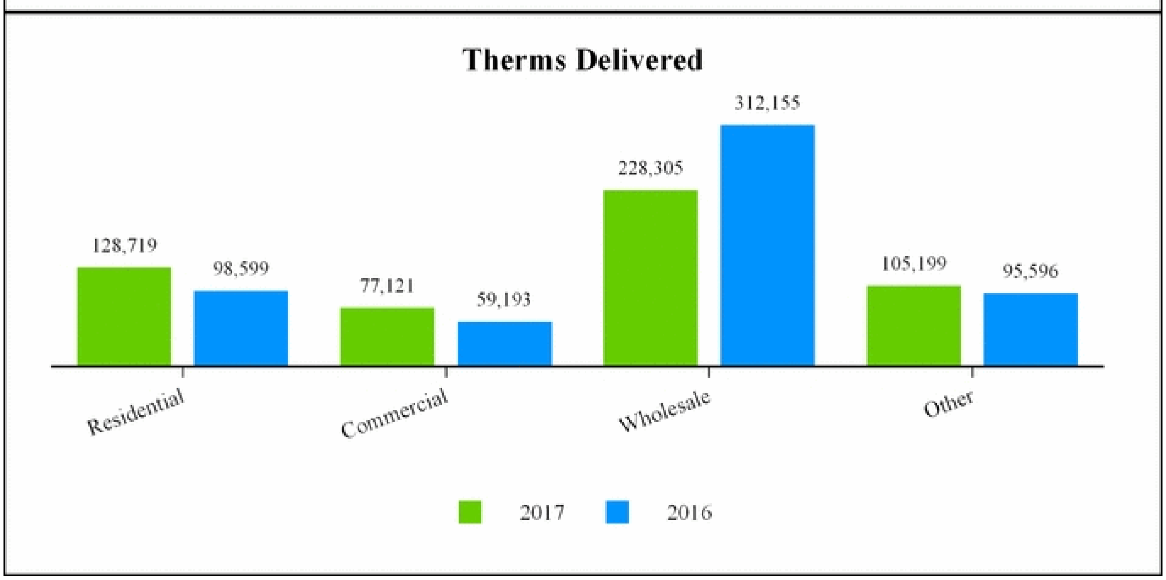
(n/a) This mechanism did not exist during this time period.

Total electric revenues decreased $3.3 million for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016 primarily reflecting the following:

- a $30.6 million increase in retail electric revenue due to an increase in total MWhs sold (increased revenues $22.2 million) and an increase in revenue per MWh (increased revenues $8.4 million).
    - The increase in total retail MWhs sold was the result of weather that was cooler than the prior year (which increased electric heating loads, partially offset by a decrease in cooling loads), as well as customer growth. Compared to the six months ended June 30, 2016, residential electric use per customer increased 10.6 percent and commercial use per customer increased 0.1 percent. Heating degree days in Spokane were 6 percent above normal and 29 percent above the first six months of 2016. Year-to-date 2016 cooling degree days were 54 percent above normal (mostly in June). However, cooling degree days were 12 percent below 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 $19.4 million decrease in wholesale electric revenues due to a decrease in sales volumes (decreased revenues $6.8 million) and a decrease in sales prices (decreased revenues $12.6 million). The fluctuation in volumes and prices was primarily the result of our optimization activities.
- a $0.8 million increase in sales of fuel due to an increase in sales of natural gas fuel as part of thermal generation resource optimization activities. For the six months ended June 30, 2017, $13.3 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the six months ended June 30, 2016, $16.3 million of these sales were made to our natural gas operations.
- a $16.2 million decrease in electric revenue due to decoupling. For the year-to-date, weather was overall cooler than normal in 2017, which resulted in decoupling rebates for the first half of 2017. Weather was warmer than normal in the first half of 2016, which resulted in significant decoupling surcharges. Decoupling mechanisms are not impacted by fluctuations in weather compared to prior year, they are only impacted by weather fluctuations as compared to normal weather.

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





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

	Natural Gas Operating Revenues	
	2017	2016
Washington		
Decoupling surcharge (rebate)	$ (5,221)	$ 6,766
Provision for earnings sharing	(617)	(536)
Idaho		
Decoupling surcharge (rebate)	$ (883)	$ 2,126
Oregon		
Decoupling surcharge (rebate)	$ (2,050)	$ 1,858

Total natural gas revenues increased $14.3 million for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016 primarily reflecting the following:

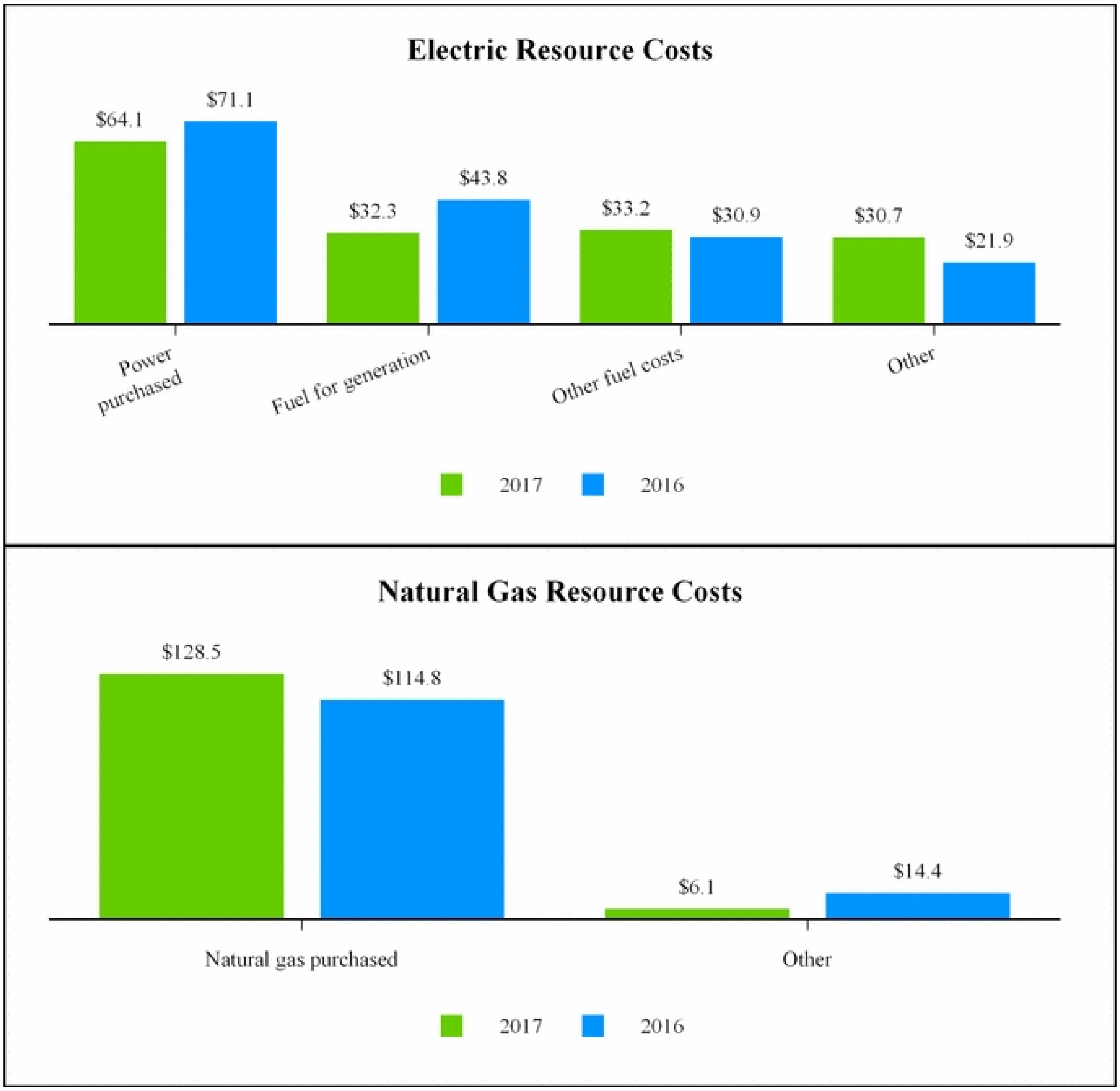
- a $33.5 million increase in natural gas retail revenues due to an increase in volumes (increased revenues $43.3 million), partially offset by lower retail rates (decreased revenues $9.8 million).
  - We sold more retail natural gas in the six months ended June 30, 2017 as compared to the six months ended June 30, 2016 due to cooler weather and customer growth. Compared to the first six months of 2016, residential natural gas use per customer increased 28 percent and commercial use per customer increased 29 percent. Heating degree days in Spokane were 6 percent above normal and 29 percent above the first six months of 2016. Heating degree days in Medford were 3 percent below normal, but 24 percent above the first six months of 2016.
  - Lower retail rates were due to PGAs, partially offset by a general rate increase in Oregon.
- a $1.0 million decrease in wholesale natural gas revenues due to a decrease in volumes (decreased revenues $22.6 million), mostly offset by an increase in prices (increased revenues $21.6 million). In the six months ended June 30, 2017, $19.5 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the six months ended June 30, 2016, $14.9 million of these sales were made to our electric generation operations. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.
- an $18.9 million decrease in natural gas revenue due to decoupling. For the year-to-date, weather was overall cooler than normal in 2017, which resulted in decoupling rebates for the first half of 2017. Weather was warmer than normal in the first half of 2016, which resulted in significant decoupling surcharges. Decoupling mechanisms are not impacted by fluctuations in weather compared to prior year, they are only impacted by weather fluctuations as compared to normal weather.

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

	Electric Customers		Natural Gas Customers	
	2017	2016	2017	2016
Residential	333,885	329,810	306,231	299,966
Commercial	42,070	41,698	35,217	34,874
Interruptible	—	—	37	38
Industrial (1)	1,327	1,347	251	256
Public street and highway lighting	562	555	—	—
Total retail customers	377,844	373,410	341,736	335,134

(1) The decrease in electric industrial customers as compared to the first half of 2016 is primarily related to a decrease in Washington irrigation customers.

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



Total resource costs in the graphs above include intracompany resource costs of $32.8 million and $31.2 million for the six months ended June 30, 2017 and June 30, 2016, respectively.

Total electric resource costs decreased $7.4 million for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016 reflecting the following:

- a $7.0 million decrease in purchased power due to a decrease in wholesale prices (decreased costs $7.5 million), partially offset by an increase in the volume of power purchases (increased costs $0.5 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the period.
- an $11.5 million decrease in fuel for generation primarily due to a decrease in thermal generation (due in part to increased hydroelectric generation).
- a $2.3 million increase in other fuel costs.
- an $8.2 million increase from amortizations and deferrals of power costs. This change was primarily to result of lower

net power supply costs.

- a $0.6 million increase in other regulatory amortizations and other electric resource costs.

Total natural gas resource costs increased $5.4 million for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016 reflecting the following:

- a $13.7 million increase in natural gas purchased due to an increase in the price of natural gas (increased costs $24.0 million), partially offset by a decrease in total therms purchased (decreased costs $10.3 million). Total therms purchased decreased due to a decrease in wholesale sales, partially offset by an increase in retail sales.
- an $11.8 million decrease from amortizations and deferrals of natural gas costs. This reflects lower natural gas prices compared to our authorized PGA rates and the deferral of these lower costs, which occurred in the current period for future rebate to customers.
- a $3.5 million increase in other regulatory amortizations.

Results of Operations - Alaska Electric Light and Power Company

Three months ended June 30, 2017 compared to the three months ended June 30, 2016 and six months ended June 30, 2017 compared to the six months ended June 30, 2016

Net income for AEL&P was $1.7 million for the three months ended June 30, 2017 compared to $1.1 million for the three months ended June 30, 2016. Net income was $5.5 million for the six months ended June 30, 2017 compared to $4.0 million for the six months ended June 30, 2016.

The increase in earnings for both the second quarter and year-to-date was primarily due to an increase in electric gross margin which was $8.7 million for the second quarter of 2017, compared to $7.0 million for the second quarter of 2016. For the year-to-date, electric gross margin was $20.9 million for the six months ended June 30, 2017, compared to $17.0 million for the six months ended June 30, 2016. The increase in electric gross margin was partially offset by an increase in operating expenses and a decrease in equity-related AFUDC due to the construction of an additional back-up generation plant in 2016.

The increase in electric gross margin was primarily related to an interim 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 expense, deferred power supply expenses and fuel expense.

While the cooler weather did have some effect on AEL&P revenues during 2017, AEL&P has a relatively stable load profile as it does not have a large population of customers in its service territory with electric heating and cooling requirements; therefore, its revenues are not as sensitive to weather fluctuations as Avista Utilities. However, AEL&P does have higher winter rates for its customers during the peak period of November through May of each year, which drives higher revenues during those periods.

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

Results of Operations - Other Businesses

Net losses for our other businesses were $1.7 million for the three months ended June 30, 2017 compared to $0.6 million for the three months ended June 30, 2016. Net losses were $1.9 million for the six months ended June 30, 2017 compared to $0.9 million for the six months ended June 30, 2016.

Net losses for the second quarter 2017 and the six months ended June 30, 2017 were primarily related to renovation expenses and increased compliance costs at one of our subsidiaries and additional losses on investments as compared to 2016. These were partially offset by a decrease in corporate costs (including costs associated with exploring strategic opportunities).

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein. Our critical accounting policies that require the use of estimates and assumptions were discussed in detail in the 2016 Form 10-K and have not changed materially from that discussion.

Liquidity and Capital Resources

Overall Liquidity

Our sources of overall liquidity and the requirements for liquidity have not materially changed in the six months ended June 30, 2017. See the 2016 Form 10-K for further discussion.

As of June 30, 2017, we had $207.3 million of available liquidity under the Avista Corp. committed line of credit and $25.0 million under the AEL&P committed line of credit. With our $400.0 million credit facility that expires in April 2021 and AEL&P's $25.0 million credit facility that expires in November 2019, we believe that we have adequate liquidity to meet our needs for the next 12 months.

Review of Cash Flow Statement

Overall

During the six months ended June 30, 2017, positive cash flows from operating activities were $228.5 million, which included contributions to our pension plan of $14.8 million. Other cash requirements included utility capital expenditures of $177.7 million, dividends of $46.2 million.

Operating Activities

Net cash provided by operating activities was $228.5 million for the six months ended June 30, 2017 compared to $156.0 million for the six months ended June 30, 2016. The increase in net cash provided by operating activities was primarily related to the amount of collateral posted for derivative instruments where we posted $5.5 million in the first half of 2017, compared to $83.5 million posted in the first half of 2016. Our collateral increased in 2016 due to a decrease in the fair value of outstanding interest rate swap derivatives at that time and also due to fewer counterparties accepting letters of credit as collateral. In 2017, more counterparties are accepting letters of credit as collateral rather than cash. In addition for the first half of 2017, we had increased net income (after consideration of non-cash items included in net income) of $235.5 million, compared to $224.0 million in 2016.

We also increased our pension contributions from $8.0 million in the first half of 2016 to $14.8 million in the first half of 2017.

Investing Activities

Net cash used in investing activities was $189.6 million for the six months ended June 30, 2017, compared to $206.6 million for the six months ended June 30, 2016. During the first half of 2017, we paid $177.7 million for utility capital expenditures compared to $182.8 million for the first half of 2016. Also, during the first half of 2017, our subsidiaries invested $10.3 million in equity and property, compared to $7.0 million invested during the first half of 2016.

Financing Activities

Net cash used by financing activities was $34.0 million for the six months ended June 30, 2017, compared to net cash provided of $53.7 million for the six months ended June 30, 2016. We had the following significant transactions:

- short-term borrowings increased by $16.0 million in the first half of 2017, compared to an increase of $55.0 million in 2016,
- cash dividends paid to Avista Corp. shareholders increased to $46.2 million (or $0.715 per share) for the first half of 2017 from $43.3 million (or $0.685 per share) for the first half of 2016, and
- issuance of $1.2 million (net of issuance costs) under share-based compensation plans. In 2016, we issued $47.2 million of common stock under sales agency agreements.

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, and excluding noncontrolling interests, consisted of the following as of June 30, 2017 and December 31, 2016 (dollars in thousands):

	June 30, 2017		December 31, 2016	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and capital leases	$ 277,814	7.8%	$ 3,287	0.1%
Short-term borrowings	136,398	3.8%	120,000	3.4%
Long-term debt to affiliated trusts	51,547	1.5%	51,547	1.5%
Long-term debt and capital leases	1,403,064	39.5%	1,678,717	47.9%
Total debt	1,868,823	52.6%	1,853,551	52.9%
Total Avista Corporation shareholders' equity	1,687,173	47.4%	1,648,727	47.1%
Total	$ 3,555,996	100.0%	$ 3,502,278	100.0%

Our shareholders' equity increased $38.4 million during the first six months of 2017 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 June 30, 2017, there were $136.0 million of cash borrowings and $56.7 million in letters of credit outstanding (which were primarily issued as collateral for our energy commodity and interest rate swap derivatives), leaving $207.3 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 June 30, 2017, we were in compliance with this covenant with a ratio of 52.6 percent.

AEL&P has a $25.0 million committed line of credit that expires in November 2019. As of June 30, 2017, 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 June 30, 2017, AEL&P was in compliance with this covenant with a ratio of 54.1 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 six months ended June 30 (dollars in thousands):

	2017	2016
Borrowings outstanding at end of period	$ 136,000	$ 160,000
Letters of credit outstanding at end of period	$ 56,703	$ 45,795
Maximum borrowings outstanding during the period	$ 136,000	$ 160,000
Average borrowings outstanding during the period	$ 105,157	$ 118,832
Average interest rate on borrowings during the period	1.67%	1.22%
Average interest rate on borrowings at end of period	1.99%	1.22%

There were no borrowings outstanding under AEL&P's committed line of credit as of June 30, 2017 and June 30, 2016.

As of June 30, 2017, Avista Corp. and its subsidiaries were in compliance with all of the covenants of their financing agreements, and none of Avista Corp.'s subsidiaries constituted a "significant subsidiary" as defined in Avista Corp.'s committed line of credit.

Equity Issuances

See "Note 9 of the Notes to Condensed Consolidated Financial Statements" for a discussion of our equity issuances during 2016 and 2017.

2017 Liquidity Expectations

In the second half of 2017, we expect to issue up to $90.0 million of long-term debt and up to $70.0 million of common stock in order to fund planned capital expenditures and maintain an appropriate capital structure.

After considering the expected issuances of long-term debt and common stock during 2017, 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.

Capital Expenditures

We are making capital investments in generation, transmission and distribution systems to preserve and enhance service reliability for our customers and replace aging infrastructure. Our estimated capital expenditures for 2017, 2018 and 2019 have not materially changed during the six months ended June 30, 2017. See the 2016 Form 10-K for further information.

Off-Balance Sheet Arrangements

As of June 30, 2017, we had $56.7 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $34.4 million as of December 31, 2016. The increase in outstanding letters of credit is partially related to negotiations with interest rate swap counterparties to accept letters of credit as collateral rather than cash collateral and also due to issuing additional letters of credit as collateral based on changes in the fair value of interest rate swap and energy commodity derivatives during the six months ended June 30, 2017.

Pension Plan

Avista Utilities

In the six months ended June 30, 2017 we contributed $14.8 million to the pension plan and we expect to contribute a total of $22.0 million in 2017. We expect to contribute a total of $110.0 million to the pension plan in the period 2017 through 2021, with annual contributions 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 4 of the Notes to Condensed Consolidated Financial Statements" for additional information regarding the pension plan.

Contractual Obligations

Our future contractual obligations have not materially changed during the six months ended June 30, 2017. See the 2016 Form 10-K for our contractual obligations.

Environmental Issues and Contingencies

Our environmental issues and contingencies disclosures have not materially changed except for the following during the six months ended June 30, 2017. See the 2016 Form 10-K for all other environmental issues and contingencies.

Climate Change - Federal Regulatory Actions

The Environmental Protection Agency (EPA) released the final rules for the Clean Power Plan (Final CPP) and the Carbon Pollution Standards (Final CPS) on August 3, 2015. The Final CPP and the Final CPS are 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 on October 23, 2015 and were immediately challenged via lawsuits by other parties.

In a separate but related rulemaking, the EPA finalized CO2 new source performance standards (NSPS) for new, modified and reconstructed fossil fuel-fired EGUs under CAA section 111(b). These EGUs fall into the same two categories of sources regulated by the Final CPP: steam generating units (also known as "utility boilers and IGCC units"), which primarily burn coal, and stationary combustion turbines, which primarily burn natural gas.

The promulgated and proposed greenhouse gas rulemakings mentioned above have been legally challenged in multiple venues. On February 9, 2016, the U.S. Supreme Court granted a request for stay, halting implementation of the CPP. On March 28, 2017, the Department of Justice has filed a motion with the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) requesting that the Court hold the cases challenging the CPP in abeyance while the EPA reviews the final rules applicable to existing, as well as to new, modified, and reconstructed electric generating units pursuant to an Executive Order issued by President Trump. The Executive Order also instructed the EPA to review the CPP rule. On April 28, 2017 the D.C.

Circuit issued orders to hold the litigation regarding the Clean Air Act §111(d) Clean Power Plan and the §111(b) New Source Performance Standards for power plants in abeyance for a period of 60 days with status reports due from the EPA every 30 days. The EPA has continued to ask the Court to hold the rules in abeyance, and, as a result of its ongoing review of the Final CPP, in June 2017 transmitted a draft proposed rule to the Office of Management and Budget. The contents of that proposed rule have not been made public. Given these ongoing developments, we cannot fully predict the outcome or estimate the extent to which our facilities may be impacted by these regulations at this time. We intend to seek recovery of any costs related to compliance with these requirements through the ratemaking process.

Enterprise Risk Management

The material risks to our businesses were discussed in our 2016 Form 10-K and have not materially changed during the six months ended June 30, 2017. Refer to the 2016 Form 10-K for further discussion of our risks and the mitigation of those risks.

Financial Risk

Our financial risks have not materially changed during the six months ended June 30, 2017. Refer to the 2016 Form 10-K. The financial risks included below are required interim disclosures, even if they have not materially changed from December 31, 2016.

Interest Rate Risk

We use a variety of techniques to manage our interest rate risks. We have an interest rate risk policy and have established a policy to limit our variable rate exposures to a percentage of total capitalization. Additionally, interest rate risk is managed by monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and establishing fixed rate long-term debt with varying maturities. See "Note 3 of the Notes to Condensed Consolidated Financial Statements" for a summary of our interest rate swap derivatives outstanding as of June 30, 2017 and December 31, 2016.

Credit Risk

Avista Utilities' contracts for the purchase and sale of energy commodities can require collateral in the form of cash or letters of credit. As of June 30, 2017, we had cash deposited as collateral in the amount of $15.9 million and letters of credit of $37.3 million outstanding related to our energy derivative contracts. Price movements and/or a downgrade in our credit ratings could impact further the amount of collateral required. See “Credit Ratings” in the 2016 Form 10-K for further information. For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below “investment grade” based on our positions outstanding at June 30, 2017, we would potentially be required to post up to $4.1 million of additional collateral. This amount is different from the amount disclosed in “Note 3 of the Notes to Condensed Consolidated Financial Statements” because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 3, this analysis takes into account contractual threshold limits that are not considered in Note 3. Without contractual threshold limits, we would potentially be required to post up to $4.7 million of additional collateral.

Under the terms of interest rate swap derivatives that we enter into periodically, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. As of June 30, 2017, we had interest rate swap derivatives outstanding with a notional amount totaling $510.0 million and we had deposited cash in the amount of $41.6 million and letters of credit of $13.1 million as collateral for these interest rate swap derivatives. If our credit ratings were lowered to below “investment grade” based on our interest rate swap derivatives outstanding at June 30, 2017, we would be required to post up to $11.2 million of additional collateral.

Energy Commodity Risk

Our energy commodity risks have not materially changed during the six months ended June 30, 2017, except as discussed below. Refer to the 2016 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of June 30, 2017 that are expected to settle in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
Remainder 2017	$ (2,485)	$ 456	$ (732)	$ (14,207)	$ (70)	$ 1,995	$ (213)	$ 5,808
2018	(6,880)	(347)	—	(9,416)	(24)	4,234	(870)	3,402
2019	(4,321)	(1,168)	(280)	(6,160)	(19)	4,569	(891)	1,557
2020	—	—	(357)	(489)	—	—	(1,256)	—
2021	—	—	—	—	—	—	(840)	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2016 that are expected to be delivered in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2017	$ (4,274)	$ 1,939	$ 97	$ (4,005)	$ (225)	$ 576	$ (2,036)	$ (3,440)
2018	(5,598)	—	—	(2,170)	(33)	854	(910)	709
2019	(3,123)	—	(235)	(3,732)	(40)	975	(927)	103
2020	—	—	(266)	(370)	—	—	(1,288)	—
2021	—	—	—	—	—	—	(869)	—
Thereafter	—	—	—	—	—	—	—	—

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

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

Item 4. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) (Act) that are designed to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company's management, including its principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. With the participation of the Company's principal executive officer and principal financial officer, the Company's management evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of June 30, 2017.

There have been no changes in the Company's internal control over financial reporting that occurred during the second quarter of 2017 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. Other Information

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Please refer to the 2016 Form 10-K for disclosure of risk factors that could have a significant impact on our results of operations, financial condition or cash flows and could cause actual results or outcomes to differ materially from those discussed in our reports filed with the U.S. Securities and Exchange Commission (including this Quarterly Report on Form 10-Q), and elsewhere. These risk factors have not materially changed from the disclosures provided in the 2016 Form 10-K, except for the following:

RISKS RELATED TO THE PROPOSED MERGER WITH HYDRO ONE

The Conditions to the Merger May Not Be Satisfied.

The proposed Merger with Hydro One requires approval by the holders of a majority of Avista Corp.'s outstanding shares of common stock and the receipt of regulatory approvals, including from the FERC, the CFIUS, the FCC, the UTC, IPUC, MPSC, OPUC, and the RCA. Such approvals may not be obtained or the regulatory bodies may seek to impose conditions on the completion of the transaction, which could cause the conditions to the Merger to not be satisfied or which could delay or increase the cost of the transaction. In addition, the failure to satisfy other closing conditions could result in a termination of the Merger Agreement by Hydro One or Avista Corp.

Termination Fee.

Upon termination of the Merger Agreement under certain specified circumstances, we will be required to pay Hydro One a Termination Fee of $103.0 million. We will also be required to pay Hydro One the Termination Fee in the event we sign or consummate any specified alternative transaction within twelve months following the termination of the Merger Agreement under certain circumstances. Any fees due as a result of termination could have a material adverse effect on our results of operations, financial condition, and cash flows.

Market Value of Avista Corp. Common Stock; Access to Capital.

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

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

In addition to these risk factors, see also “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.

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

(a) Not applicable

(b) Not applicable

(c) Not applicable

Item 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

2.1	Agreement and Plan of Merger, dated as of July 19, 2017, by and among Avista Corporation, Hydro One Limited, Olympus Holding Corp. and Olympus Corp. (1)
12	Computation of ratio of earnings to fixed charges (2)
15	Letter Re: Unaudited Interim Financial Information (2)
31.1	Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002) (2)
31.2	Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002) (2)
32	Certification of Corporate Officers (Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002) (3)
101	The following financial information from the Quarterly Report on Form 10−Q for the period ended June 30, 2017, formatted in XBRL (Extensible Business Reporting Language) and filed electronically herewith: (i) the Condensed Consolidated Statements of Income; (ii) Condensed Consolidated Statements of Comprehensive Income; (iii) the Condensed Consolidated Balance Sheets; (iv) the Condensed Consolidated Statements of Cash Flows; (v) the Condensed Consolidated Statements of Equity; and (vi) the Notes to Condensed Consolidated Financial Statements. (2)

(1) Previously filed as exhibit 2.1 to the registrant's Current Report on Form 8-K, filed as of July 19, 2017 and incorporated herein by reference.

(2) Filed herewith.

(3) Furnished herewith.

SIGNATURE

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

AVISTA CORPORATION
(Registrant)

Date: August 1, 2017

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

Exhibit 12

AVISTA CORPORATION

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

	Six months ended	Years Ended December 31				
	June 30, 2017	2016	2015	2014	2013	2012
Fixed charges, as defined:						
Interest charges	$ 47,538	$ 86,897	$ 80,613	$ 74,025	$ 73,772	$ 71,843
Amortization of debt expense and premium - net	1,583	3,391	3,415	3,635	3,813	3,803
Interest portion of rentals	627	1,324	1,287	1,187	1,146	1,294
Total fixed charges	$ 49,748	$ 91,612	$ 85,315	$ 78,847	$ 78,731	$ 76,940
Earnings, as defined:						
Pre-tax income from continuing operations	$ 130,254	$ 215,402	$ 185,619	$ 192,106	$ 162,347	$ 116,567
Add (deduct):						
Capitalized interest	(1,614)	(2,651)	(3,546)	(3,924)	(3,676)	(2,401)
Total fixed charges above	49,748	91,612	85,315	78,847	78,731	76,940
Total earnings	$ 178,388	$ 304,363	$ 267,388	$ 267,029	$ 237,402	$ 191,106
Ratio of earnings to fixed charges	3.59	3.32	3.13	3.39	3.02	2.48

Exhibit 15

August 1, 2017

To the Board of Directors and Shareholders of Avista Corporation
1411 East Mission Ave
Spokane, Washington 99202

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited interim financial information of Avista Corporation and subsidiaries for the periods ended June 30, 2017 and 2016, as indicated in our report dated August 1, 2017; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, is incorporated by reference in Registration Statement Nos. 333-33790, 333-126577, 333-179042 and 333-208986 on Form S-8 and in Registration Statement No. 333-209714 on Form S-3.

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

/s/ Deloitte & Touche LLP

Seattle, Washington

Exhibit 31.1

CERTIFICATION

I, Scott L. Morris, certify that:

1. I have reviewed this report on Form 10-Q of Avista Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/ Scott L. Morris

Scott L. Morris
Chairman of the Board, President
and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, certify that:

1. I have reviewed this report on Form 10-Q of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2017

/s/ Mark T. Thies

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

Exhibit 32

AVISTA CORPORATION

CERTIFICATION OF CORPORATE OFFICERS

(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the

Sarbanes-Oxley Act of 2002)

Each of the undersigned, Scott L. Morris, Chairman of the Board, President and Chief Executive Officer of Avista Corporation (the "Company"), and Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 1, 2017

/s/ Scott L. Morris

Scott L. Morris
Chairman of the Board, President
and Chief Executive Officer

/s/ Mark T. Thies

Mark T. Thies
Senior Vice President,
Chief Financial Officer, and Treasurer

hydro One

POWERING FORWARD

2016 ANNUAL REPORT

ONE OF NORTH AMERICA'S LARGEST ELECTRIC UTILITIES (TSX: H)

Hydro One Limited is Canada's largest pure-play electric transmission and distribution utility with $25 billion in assets and annual revenues of over $6.5 billion. It transmits and distributes electricity safely and reliably across the Province of Ontario, home to 38 percent of the country's population.

Hydro One owns and operates a 30,000 circuit km high-voltage transmission network transmitting 98 percent of Ontario's electric capacity, and a 123,000 circuit km lower-voltage distribution network serving 75 percent of the geography of the province and more than 1.3 million residential and business customers. Hydro One Limited became a public company coincident with its initial public offering in November 2015, and its common shares are listed on the Toronto Stock Exchange (TSX: H).

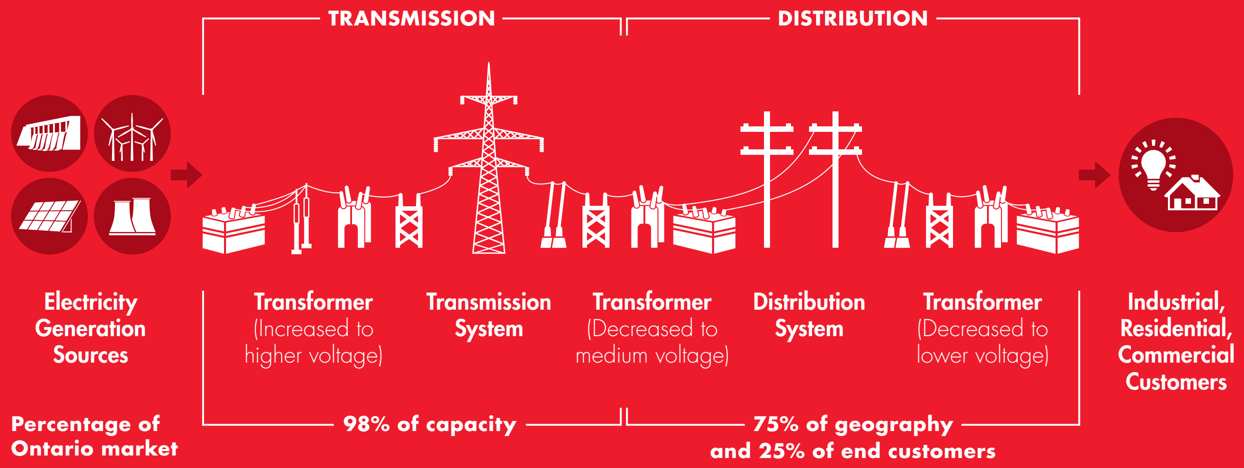
HYDRO ONE'S BUSINESS

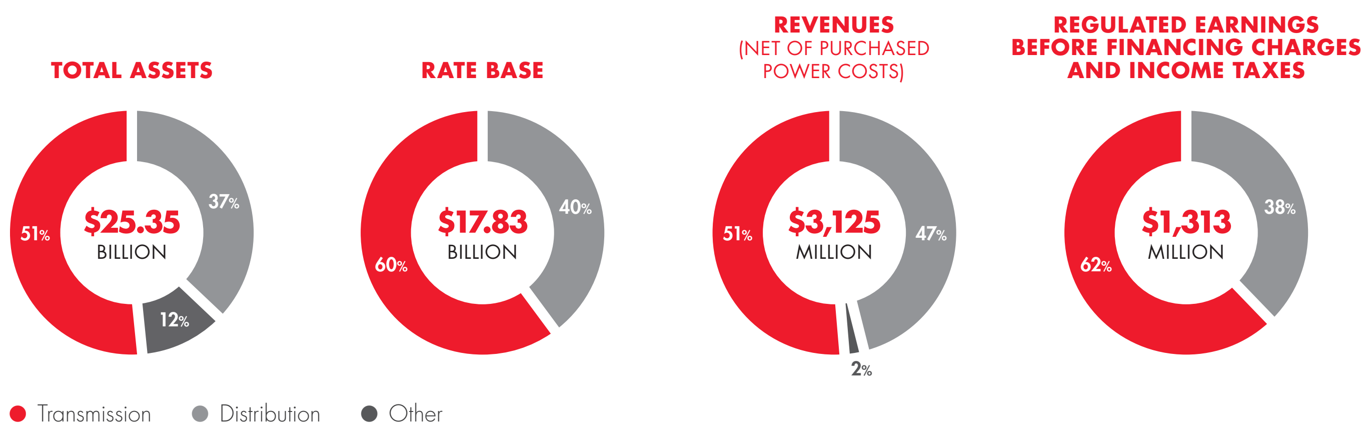
YEAR ENDED DECEMBER 31, (CAD $ millions, except per share amounts)	**2016**	**2015**
Revenues	**$ 6,552**	$ 6,538
Purchased power	**3,427**	3,450
Revenues (net of purchased power)	**3,125**	3,088
Operation, maintenance and administration	**1,069**	1,135
Depreciation and amortization	**778**	759
Income before financing charges and income tax expense	**1278**	1,194
Financing charges	**393**	376
Income tax expense	**139**	105
Net income attributable to common shareholders	**721**	690
Diluted earnings per common share	**1.21**	1.39
Adjusted diluted earnings per common share [1]	**1.21**	1.16
Net cash from (used in) operating activities	**1,656**	(1,253)
Adjusted net cash from operating activities [2]	**1,656**	1,557
Capital investments	**1,697**	1,663
Transmission – average monthly Ontario 60-minute peak demand *(MW)*	**20,690**	20,344
Distribution – electricity distributed to Hydro One customers *(GWh)*	**26,289**	28,764

[1] 2015 Adjusted earnings per share (EPS) is calculated using the number of common shares outstanding at December 31, 2016

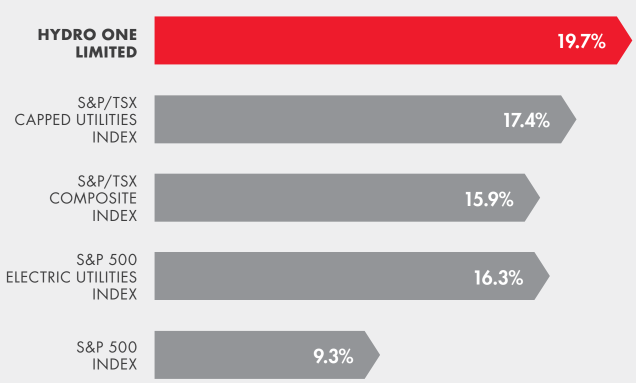
[2] 2015 amount excludes the $2,810 million non-cash impact of IPO-related adjustments

HYDRO ONE'S ROLE
IN THE ELECTRIC POWER SYSTEM





TOTAL SHAREHOLDER RETURN*
NOVEMBER 5, 2015 IPO TO DECEMBER 31, 2016



*Source: Bloomberg and S&P

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"Hydro One has achieved much over this past year while making significant progress in laying the foundation and building the organizational momentum to deliver increasing value for its customers and shareholders in the years to come."

A MESSAGE FROM **THE CHAIR OF THE BOARD**

Dear fellow shareholders,

2016 was Hydro One's first full year as a public company, and its evolution to a more broadly owned and customer-focused organization is well underway. The company has achieved much over this past year, including executing its 2016 financial and operating plans and generating total shareholder return of 19.7% since the November 2015 initial public offering. It has also made significant progress in laying the foundation to deliver increasing value for its customers and shareholders in the years to come.

One of President and Chief Executive Officer Mayo Schmidt's key objectives over the past year was to significantly strengthen the company's senior leadership team, and in that regard we now have new executives heading Hydro One's operations, customer service, legal, and strategy functions. Each of these individuals has brought significant experience and capabilities to Hydro One, and the Board of Directors is very confident that we now have in place the depth and breadth of leadership expertise that will further accelerate the company's evolution.

In April 2016, the Province of Ontario sold an additional 15% of its stake in Hydro One to the public in a very successful secondary offering. This followed the November 2015 initial public offering of the shares of Hydro One, and served to double the public float of the company to 30% of shares outstanding while at the same time measurably increasing the trading volume and liquidity of the shares. This transaction was not dilutive to our existing public shareholders, and was another step by the Province towards its stated goal of reducing its ownership of Hydro One to 40%.

While the Province of Ontario remains a significant shareholder of Hydro One, the autonomy of the company and independence of our Board of Directors is enshrined in a governance agreement between Hydro One and the Province. This governance agreement was executed in advance of last year's initial public offering and has operated as designed to ensure that the company is governed as an independent commercial entity with the Province's role limited to that of a shareholder.

I would like to recognize my fellow Board members for their service over this busy period of change. Our Board is comprised of a diverse and accomplished group of proven leaders, each of whom is very committed to the success of Hydro One and the highest standards of corporate governance. The Board has been highly engaged with Mayo Schmidt and his leadership team in defining the strategy for the organization and charting the path forward over the course of the next few years.

I would also like to acknowledge the hard work and commitment of the more than 5,500 regular employees of Hydro One. This team of dedicated professionals works tirelessly -- often around the clock and in potentially hazardous weather and conditions -- to ensure that electric power is transmitted and distributed safely, reliably and cost-effectively to the millions of citizens of Ontario and the communities in which they live and work.

Thank you for your investment and continued support,

DF Denison

DAVID F. DENISON, O.C.
Chair of the Board
Hydro One Limited

"We have assembled a team of talented and deeply experienced leaders who are dedicated to transforming Hydro One into a more disciplined, customer-focused and commercially oriented electric transmission and distribution service provider."

A MESSAGE FROM THE PRESIDENT AND CEO

Dear fellow shareholders,

This is a new era at Hydro One. 2016 was a transformative year as we embarked on our journey from good to great. In this first full year as a public company, we undertook a company-wide systematic review of our business. Through this intensive process, we identified a number of initiatives, metrics and targets that will enable us to drive greater efficiency and effectiveness across customer service, operations, procurement, network planning, capital deployment and administration.

Accordingly, we have assembled a team of talented and deeply experienced leaders who are dedicated to transforming Hydro One into a more disciplined, customer-focused and commercially oriented electric transmission and distribution service provider. We are becoming significantly more customer and performance driven by focusing on company-wide accountability, productivity, and efficiency while also engaging more proactively with our communities and First Nations and Métis partners.

Many Ontarians feel the pressure of increases to their electricity bills, so we are doing our part to keep Hydro One's portion of the bill as low as possible. We are also providing customers with meaningful conservation programs so they can take greater control of their consumption and manage their bills. Part of this move involves information technology investments that enable the shift from paper-based systems to increasingly mobile, online and paperless technologies.

Hydro One's employees have embraced our transformational journey to becoming a commercial enterprise, one focused on delivering value for customers and shareholders. This transformation is central to our actions and strategies, and is enshrined in all that we endeavour to achieve. As we move the organization forward and modernize Ontario's electrical grid, I believe that we have multiple opportunities to create increasing value for our customers and shareholders alike.

While we are fortunate to have a strong foundation for growth upon which to build, we are also aware that there are opportunities for us to enhance customer service and improve our execution capabilities across the business. We also appreciate the criticality of accelerating the pace of upgrading Ontario's aging electric power system and the significant infrastructure investment that is needed to build and maintain a strong, modern and reliable grid.

We made important progress this year on the regulatory front, where we now have a plan with a clear line of sight to the imminent transition from a cost of service-based regulatory model to a more dynamic performance-based, customer-focused regulatory model. We are fully engaged and gaining traction on this front in both segments of our regulated business. We expect to complete the transition to a performance-based regulatory framework in our distribution segment in early 2018 and in our transmission segment in early 2019.

In addition to the significant value we intend to create in improving the performance of our substantial existing operations, there is also value to be created in continuing to lead the consolidation of what is still a fragmented system of electric utility assets in Ontario. As such, during 2016 we significantly stepped up the rigour and capabilities around how we acquire and integrate other electric utilities. Our successful integration of the Haldimand and Woodstock municipal utilities is a good indicator of things to come. During the year, we also completed the acquisition of Great Lakes Power Transmission and announced the acquisition of Orillia Power Distribution, two regulated electric utilities in Ontario which further add to our leadership position.

My thanks go out to the thousands of Hydro One employees across Ontario for embracing this transformational journey and their unwavering commitment to our customers. I also extend my appreciation to our Board of Directors for its support and confidence in management.

The future is bright and we will continue to power forward,

Mayo Schmidt

MAYO SCHMIDT
President and Chief Executive Officer
Hydro One Limited

IN 2016, HYDRO ONE COMPLETED THE PURCHASE OF GREAT LAKES POWER TRANSMISSION, THE SECOND LARGEST ELECTRICITY TRANSMITTER IN ONTARIO. THIS ACQUISITION INCREASED HYDRO ONE'S TRANSMISSION CAPACITY IN ONTARIO TO 98%, WHILE IMPROVING THE COMPANY'S ABILITY TO CONNECT GENERATORS IN NORTHERN ONTARIO TO ELECTRICITY DEMAND IN SOUTHERN ONTARIO.

ELECTRIC TRANSMISSION SEGMENT

The scale of Hydro One's transmission operations increased during 2016 to approximately 30,000 circuit-kilometres of high-voltage lines. Hydro One transmits high-voltage electricity from nuclear, hydroelectric, natural gas, wind and solar generation sources to local distribution companies and to directly connected industrial customers across Ontario.

Hydro One's transmission assets can be divided into three main categories:

Transmission stations

Used for the delivery of power, voltage transformation and switching, the stations serve as connection points for both customers and generators.

Transmission lines

Bulk transmission lines deliver power from generating stations or connections to receiving terminal stations. Area supply lines take power from the network and transmit it to customer supply transmission stations at customer load centres.

Network operations

The Ontario Grid Control Centre manages all of Hydro One's transmission and sub-transmission operations.

During 2016, capital investments in Hydro One's transmission segment totaled $988 million, including expenditures on the following projects:

TORONTO MIDTOWN TRANSMISSION REINFORCEMENT PROJECT

In 2016, Hydro One substantially completed work on the $118 million Toronto Midtown Transmission Reinforcement Project which refurbished the existing transmission infrastructure that serves midtown Toronto and areas to the west. This five-year project replaced 14,500 metres of transmission cables and provides 100 megawatts of additional capacity to serve the local distribution company and its customers.

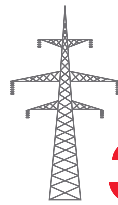
GUELPH AREA TRANSMISSION REFURBISHMENT PROJECT

Hydro One substantially completed the $87 million Guelph Area Transmission Refurbishment Project that will help meet the electricity needs of the growing southwestern Ontario region. The project included upgrading a five-kilometre section of existing transmission lines, and installing new transformer and switching equipment at the transformer station. More than 340 construction professionals were involved in the construction phase of the project.

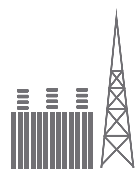
COLLABORATION WITH LONDON HYDRO

Hydro One entered into a collaborative investment with London Hydro to modernize the equipment in Hydro One's Nelson Transformer Station. Hydro One identified a need to replace aging equipment and London Hydro contributed financially for a voltage conversion of the station to be consistent with the other six local transformer stations, allowing the entire London Hydro system to be interconnected. The project will also increase the reliability of supply to an important station that serves much of downtown London.

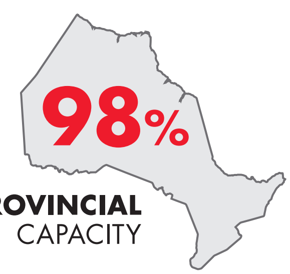
These projects together with many others underway ensure that Ontarians continue to receive a safe, reliable supply of electricity now, and for years to come.



30,000
CIRCUIT KILOMETRES
OF HIGH-VOLTAGE LINES



306
TRANSMISSION
STATIONS



ONE OF NORTH AMERICA'S LARGEST ELECTRIC POWER TRANSMITTERS

Photo courtesy of Brian Pieters Photography
www.pietersphoto.com

HYDRO ONE'S 5,500 SKILLED AND DEDICATED EMPLOYEES SERVE 1.3 MILLION VALUED RESIDENTIAL AND BUSINESS CUSTOMERS ACROSS ONTARIO. HYDRO ONE IS THE PROVINCE'S LARGEST LOCAL ELECTRIC POWER DISTRIBUTION COMPANY WITH APPROXIMATELY 123,000 CIRCUIT KILOMETRES OF POWER LINES.

ELECTRIC DISTRIBUTION SEGMENT

Operating in rural, suburban and urban communities spread across the province of Ontario, home to 38 percent of the population of Canada, Hydro One possesses significant economies of scale and brings to bear a strong commitment to ensuring a modern and reliable local electricity system for its 1.3 million customers. This commitment also includes serving customers in 21 remote communities spread across the far reaches of northern Ontario that are not connected to the electricity transmission grid.

CUSTOMER CONSULTATION

In mid-2016, Hydro One announced a province-wide consultation process to seek input from its customers on the development of a five-year rate plan that will help shape future investments in Hydro One's electric distribution system. The goal of the consultation was to better understand how Hydro One's customers' needs are being met by the current system, and the types of reliability and service improvements customers would value most. This included addressing aging electricity infrastructure, system repairs and responding to power outages, power quality and costs, as well as new products, services and web-enabled tools to make it easier for customers to do business with Hydro One.

The feedback influenced detailed plans that the company will submit to the Ontario Energy Board, who will ultimately determine the investments and rate plans for Hydro One's local distribution segment for the 2018 through 2022 period.

ACQUISITION OF ORILLIA POWER

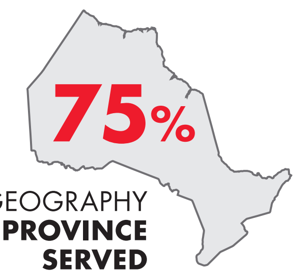
In August 2016, Hydro One announced that it reached a definitive agreement to acquire Orillia Power Distribution Corporation in a transaction valued at over $41 million. Hydro One will integrate into its operations approximately 14,000 customers located in Simcoe County, home to a population of more than 30,000 and part of the Huronia region of Central Ontario.

Hydro One's current service territory includes the areas surrounding the City of Orillia and this acquisition enables Hydro One to realize operational synergies over time. After closing, Hydro One also intends to construct several grid control and operating facilities in Orillia. The acquisition is conditional upon the satisfaction of customary closing conditions and approval of the Ontario Energy Board.

SERVING MANITOULIN ISLAND

In October 2016, Hydro One announced that a new distribution station will be built to serve customers on Manitoulin Island, located in northern Ontario on Lake Huron. The new distribution station will replace the Little Current Distribution Station, which was originally built in 1950, and will help improve reliability and increase capacity for the approximately 10,000 customers who live on Manitoulin Island.

123,000
CIRCUIT KILOMETRES
OF LOCAL DISTRIBUTION LINES



GEOGRAPHY
OF **PROVINCE SERVED**

1.3M
RESIDENTIAL & BUSINESS CUSTOMERS
ACROSS ONTARIO

ONTARIO'S LARGEST LOCAL ELECTRIC POWER DISTRIBUTION COMPANY

SERVING CUSTOMERS AND COMMUNITIES RELIABLY AND SAFELY

SERVING
CUSTOMERS & COMMUNITIES

CUSTOMER SERVICE	RELIABILITY	SAFETY
FIRST NATIONS PARTNERSHIPS	SUSTAINABILITY	DIVERSITY

Throughout 2016, Hydro One's skilled and dedicated employees responded 24 hours a day, seven days a week to quickly and safely restore power for customers through often extremely challenging weather, terrain and circumstances. Hydro One also continued to provide new and enhanced programs and services to further define the company's commitment to customer service and energy conservation.

PROACTIVE OUTAGE ALERTS

In early 2016, Hydro One was the first utility in Canada to offer customers proactive outage alerts. Customers who register for this service receive personalized email or text alerts about outages that may affect their homes, cottages, farms or small businesses, as well as information on estimated times of restoration. Since launching the program, Hydro One has sent hundreds of thousands of proactive alerts to customers. This service is an extension of Hydro One's existing suite of outage communication tools, which includes online outage maps and smartphone apps.

GET LOCAL IN FIRST NATIONS COMMUNITIES

Hydro One began to offer a new service model in First Nations and Métis communities which focuses on local, face-to-face interactions to ensure customers are informed of and have access to all of the conservation and assistance programs the company offers. Meeting with Chiefs and Councils, representatives from Hydro One's Customer Service team visit communities throughout the province and conduct information-sharing sessions with customers.

For further information on Hydro One's commitments to customers go to
▶ HydroOne.com/Commitments

FARM RAPID RESPONSE TEAM

Hydro One announced the launch of its Farm Rapid Response Team that assists the company's 13,000 farming customers to identify, assess and mitigate on-farm electrical issues. This new approach better serves the needs of Hydro One's farming customers and was developed in partnership with the Ontario Federation of Agriculture. This streamlined process also provides Hydro One's farming customers a single, specialized point of contact to better assist with their specific on-farm concerns.

PAPERLESS BILLING AND HIGH USAGE ALERTS

In late 2016, Hydro One launched paperless billing notifications and high usage alerts to provide customers with more visibility and control over their accounts and energy use. With billing notifications, customers sign up to receive paperless billing together with personalized insights and program promotions, which also provide a new online self-service channel for customers as an alternative to contacting the call centre. With high usage alerts, customers receive emails or text messages if their usage during a billing period is trending higher than a predefined threshold. Customers also receive guidance on how they can adjust their energy use before the end of the billing period. Through the enhanced web portal, customers can also easily find more information about their energy use, as well as explore a wide range of energy tips and conservation programs provided by Hydro One.

COMMUNITY INVESTMENT

Throughout 2016, Hydro One committed millions of dollars in donations and sponsorships to communities it serves across Ontario. The contributions supported community projects such as the Markstay outdoor ice rink roof-building project for the local municipality, benefiting the community's local youth. Other community initiatives include the company's partnership with Right to Play's Promoting Life-Skills in Aboriginal Youth program, a non-profit organization that aims to deliver safe, fun and educational programming to Aboriginal youth.

TRANSMITTING AND DELIVERING SOME OF THE CLEANEST ELECTRIC POWER IN NORTH AMERICA

AS A STEWARD OF THE GRID, HYDRO ONE IS FOCUSED ON TRANSMITTING AND DELIVERING SAFE, CLEAN AND SUSTAINABLE ENERGY. THIS YEAR THE COMPANY PRODUCED ITS FIRST CORPORATE SOCIAL RESPONSIBILITY REPORT, ONE WHICH ADHERES TO THE GUIDELINES FOR THE G4 GLOBAL REPORTING INITIATIVE AND IS PART OF A CONTINUED EFFORT BY THE COMPANY TO ENHANCE THE TRANSPARENCY, ACCOUNTABILITY AND LINE OF SIGHT TO ITS SUSTAINABLE OPERATIONS.

ENVIRONMENTAL SUSTAINABILITY

HEBER DOWN CONSERVATION AREA

Hydro One's Forestry team partnered with the Central Lake Ontario Conservation Authority and neighbouring utilities to mitigate the spread of Phragmites, an invasive species, on 3,500 square metres of a right-of-way corridor in the Heber Down Conservation Area. Challenging and costly to remove, such invasive species threaten lakes, rivers and forests. Together with a local contractor and using a variety of control methods based on location, density and surrounding vegetation of each area, the company began work on eliminating the invasive species from its right-of-way. With thousands of kilometres of transmission line corridors crossing the province, the company has taken a leadership role in engaging with local stakeholders, taking a proactive approach to land management and pooling community resources to manage the spread of invasive species.

VEGETATION MANAGEMENT

To ensure the continued safe operation of Hydro One's transmission and distribution lines, the company conducts province-wide vegetation management operations to maintain reliability across the system. As part of the company's ongoing commitment to local communities, Hydro One has consulted with conservation authorities and is working with local seed distributors to develop and test pollinator-friendly seed mixes. Pollinators include various forms of bees, wasps, ants, flies, moths, beetles, bats and birds. These species feed on nectar and pollen from plants and their populations in Ontario are generally in decline due to habitat loss, disease, pesticide use and climate change. To mitigate this, Hydro One is working to incorporate pollinator-friendly seed as part of its vegetation management work in appropriate areas as an alternative to grass seed. Locally, this work supports provincial initiatives like the Pollinator Health Action Plan developed by the Ontario Ministry of Agriculture, Food and Rural Affairs.

CORPORATE KNIGHT'S BEST 50 CORPORATE CITIZENS

Hydro One was ranked as the top utility in the 15th annual ranking of the 2015 Corporate Knights Canada's Best 50 Corporate Citizens. The Best 50 Corporate Citizens in Canada ranking assesses a broad range of Canadian enterprises on a set of 12 sustainability metrics, including carbon, water and waste productivity, percent of taxes paid, leadership gender diversity, innovation, health and safety performance, and pension fund quality. Being recognized as one of Canada's Best 50 Corporate Citizens is a testament to Hydro One's core values and demonstrates that the company continues to develop a strong culture of sustainability and corporate responsibility. Customers, investors and citizens of Ontario should expect that Hydro One will power forward in its responsible leadership on Corporate Citizenship in Canada.

For further information on Hydro One's commitments to the environment, go to
▶ HydroOne.com/OurCommitment

CORPORATE GOVERNANCE
OVERVIEW

★ CHAIR ● MEMBER

BOARD OF DIRECTORS AND COMMITTEES	AUDIT	NOMINATING, CORPORATE GOVERNANCE, PUBLIC POLICY AND REGULATORY	HUMAN RESOURCES	HEALTH, SAFETY, ENVIRONMENT AND FIRST NATIONS AND MÉTIS
David Denison – Chair				
Mayo Schmidt – President and CEO				
Ian Bourne		●	★	
Charles Brindamour	●		●	
Marc Caira		●	●	
Christie Clark		●	●	
George Cooke	●			●
Marianne Harris			●	★
James Hinds	●			●
Kathryn Jackson		●		●
Roberta Jamieson	●			●
Frances Lankin	●	●		
Philip Orsino	★	●		
Jane Peverett		★	●	
Gale Rubenstein			●	●

Hydro One and its independent Board of Directors recognize the importance of corporate governance to the effective management of the company. Independence, integrity and accountability are the foundation of the company's approach to corporate governance. It is in the long-term best interests of shareholders as well as customers and promotes and strengthens relationships with employees, the communities in which the company operates and other stakeholders of the company. The Board of Directors is firmly supported in these commitments by a governance agreement between Hydro One and the Province of Ontario, which was executed in advance of the November 2015 initial public offering of the company and assures that the Province's role is limited to that of a shareholder and not a manager of the business.

Hydro One's Board of Directors is composed of a diverse and accomplished group of independent, proven business leaders with deep corporate governance experience. The Board's primary role is overseeing corporate performance and the quality, depth and continuity of management required to meet the company's strategic objectives. Hydro One is committed to best practices of corporate governance, and regularly reviews the company's governance practices in response to changing governance expectations and regulations. The Company's practices are fully aligned with the rules and regulations issued by Canadian Securities Administrators and the Toronto Stock Exchange, including national corporate governance guidelines and related disclosure requirements.

HYDRO ONE'S GOOD GOVERNANCE PRACTICES

FULLY INDEPENDENT BOARD (EXCLUDING CEO)	CODE OF BUSINESS CONDUCT AND WHISTLEBLOWER HOTLINE	ANNUAL REVIEWS OF BOARD AND COMMITTEE PERFORMANCE
BOARD EDUCATION SESSIONS	COMMITTEE AUTHORITY TO RETAIN INDEPENDENT ADVISORS	BOARD AND COMMITTEE IN-CAMERA DISCUSSIONS
TERM LIMITS FOR DIRECTORS	DIRECTOR SHARE OWNERSHIP GUIDELINES	COMMITMENT TO DIRECTOR DIVERSITY
SEPARATE BOARD CHAIR AND CEO	MAJORITY VOTING FOR DIRECTORS	GOVERNANCE AGREEMENT WITH PROVINCE

For a complete description of Hydro One's corporate governance structure and practices and individual director biographical information, go to
▶ HydroOne.com/Investors

TEN REASONS TO INVEST IN HYDRO ONE

1

One of the largest pure play electric utilities in North America, with significant scale and a leadership position in Canada's most populated province

2

Unique combination of electric transmission and local distribution, with no material exposure to commodity prices

3

Business is 99 percent regulated and operates in a stable, transparent and collaborative rate-regulated environment

4

Consistent rate base growth expected under multi-year capital investment program to upgrade aging electric power system infrastructure

5

Strong governance structure and a fully independent Board allow company to operate autonomously, transform its culture and drive shareholder value creation on multiple fronts

6

Timing of operational transformation coincident with transition to Ontario's incentive based regulatory framework expected to create value for both customers and shareholders

7

Proven management team with demonstrated experience in transforming organizations, accelerating performance and creating significant shareholder value

8

Attractive dividend yield with 70 – 80 percent target payout ratio and opportunity for growth with rate base expansion, efficiency realization and continued consolidation

9

Strong 'A'-rated investment grade balance sheet with one of the highest-quality credit profiles in the North American utility sector

10

A unique opportunity to participate in the transformation of a premium, large-scale utility

2016 FINANCIAL REPORT

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1 MANAGEMENT'S DISCUSSION AND ANALYSIS

2 CONSOLIDATED FINANCIAL STATEMENTS

3 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Discussion and Analysis

For the years ended December 31, 2016 and 2015

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the consolidated financial statements and accompanying notes (the Consolidated Financial Statements) of Hydro One Limited (Hydro One or the Company) for the year ended December 31, 2016. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. This MD&A provides information for the year ended December 31, 2016, based on information available to management as of February 9, 2017.

The comparative information consists of the results of Hydro One Inc. up to October 31, 2015, and the consolidated results of Hydro One and Hydro One Inc. from November 1, 2015 to December 31, 2015. See further details in section "Other Developments – Change in Hydro One Ownership Structure".

Consolidated Financial Highlights And Statistics

Year ended December 31 *(millions of dollars, except as otherwise noted)*	2016	2015	Change
Revenues	6,552	6,538	0.2%
Purchased power	3,427	3,450	(0.7%)
Revenues, net of purchased power	3,125	3,088	1.2%
Operation, maintenance and administration costs	1,069	1,135	(5.8%)
Depreciation and amortization	778	759	2.5%
Financing charges	393	376	4.5%
Income tax expense	139	105	32.4%
Net income attributable to common shareholders of Hydro One	721	690	4.5%
Basic earnings per common share (EPS)	$ 1.21	$ 1.39	(12.9%)
Diluted EPS	$ 1.21	$ 1.39	(12.9%)
Basic pro forma adjusted non-GAAP EPS (Adjusted EPS)[1]	$ 1.21	$ 1.16	4.5%
Diluted Adjusted EPS[1]	$ 1.21	$ 1.16	4.5%
Net cash from (used in) operating activities	1,656	(1,248)	232.7%
Adjusted net cash from operating activities[1]	1,656	1,562	6.0%
Funds from (used in) operations (FFO)[1]	1,494	(1,479)	201.0%
Adjusted FFO[1]	1,494	1,331	12.2%
Capital investments	1,697	1,663	2.0%
Assets placed in-service	1,605	1,476	8.7%
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	20,690	20,344	1.7%
Distribution: Electricity distributed to Hydro One customers *(GWh)*	26,289	28,764	(8.6%)

December 31	2016	2015
Debt to capitalization ratio[2]	52.6%	50.7%

[1] See section "Non-GAAP Measures" for description and reconciliation of Adjusted EPS, adjusted net cash from operating activities, FFO and Adjusted FFO.

[2] Debt to capitalization ratio has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

Overview

Hydro One is the largest electricity transmission and distribution company in Ontario. Through its wholly owned subsidiary, Hydro One Inc., Hydro One owns and operates substantially all of Ontario's electricity transmission network, and an approximately 123,000 circuit km low-voltage distribution network. Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

Transmission Segment

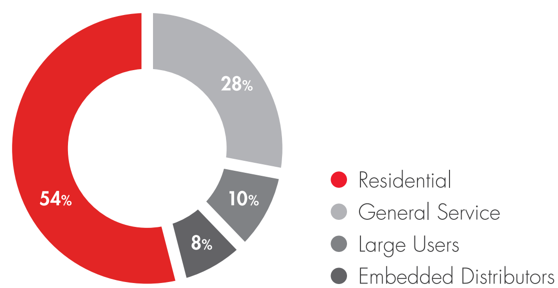
Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on revenue approved by the Ontario Energy Board (OEB). The Transmission Business consists of the transmission system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP (Great Lakes Power)), as well as a 66% interest in B2M Limited Partnership (B2M LP), a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. The Company's transmission business is a rate-regulated business that earns revenues mainly from charging transmission rates that are approved by the OEB. The transmission business represented approximately 51% of the Company's total assets as at December 31, 2016, and approximately 51% of its 2016 revenues, net of purchased power.

	2016	2015
Electricity transmitted[1] *(MWh)*	136,989,747	137,011,780
Transmission lines spanning the province *(circuit-kilometres)*	30,259	29,355
Rate base *(millions of dollars)*	10,775	10,175
Capital investments *(millions of dollars)*	988	943
Assets placed in-service *(millions of dollars)*	937	696

1 Electricity transmitted represents total electricity transmission in Ontario by all transmitters.

Distribution Segment

Hydro One's distribution business is the largest in Ontario and consists of the distribution system operated by Hydro One Inc.'s subsidiaries Hydro One Networks and Hydro One Remote Communities Inc. The Company's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that are approved by the OEB. The distribution business represented approximately 37% of the Company's total assets as at December 31, 2016, and approximately 47% of its 2016 revenues, net of purchased power.



	2016	2015
Electricity distributed to Hydro One customers *(GWh)*	26,289	28,764
Electricity distributed through Hydro One lines *(GWh)*[1]	37,394	40,721
Distribution lines spanning the province *(circuit-kilometres)*	122,599	123,425
Distribution customers *(number of customers)*	1,355,302	1,347,231
Rate base *(millions of dollars)*	7,056	6,739
Capital investments *(millions of dollars)*	703	711
Assets placed in-service *(millions of dollars)*	662	775

1 Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the Independent Electricity System Operator (IESO).

Other Business Segment

Hydro One's other business segment consists of the Company's telecommunications business and certain corporate activities. The telecommunications business provides telecommunications support for the Company's transmission and distribution businesses, and also offers communications and IT solutions to organizations with broadband network requirements utilizing Hydro One Telecom Inc.'s (Hydro One Telecom) fibre optic network to provide diverse, secure and highly reliable broadband connectivity. Hydro One's other business segment is not rate-regulated. This segment represented approximately 12% of Hydro One's total assets as at December 31, 2016, and approximately 2% of its 2016 revenues, net of purchased power.

Primary Factors Affecting Results Of Operations

Transmission Revenues

Transmission revenues primarily consist of the Company's transmission rates approved by the OEB which are charged based on the monthly peak electricity demand across Hydro One's high-voltage network. Transmission rates are designed to generate revenues necessary to construct, upgrade, extend and support a transmission system with sufficient capacity to accommodate maximum forecasted demand and a regulated return on the Company's investment. Peak electricity demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting electricity to markets outside of Ontario. Ancillary revenues include revenues from providing maintenance services to power generators and from third-party land use.

Distribution Revenues

Distribution revenues include the distribution rates approved by the OEB and amounts to recover the cost of purchased power used by the customers of the distribution business. Distribution rates are designed to generate revenues necessary to construct and support the local distribution system with sufficient capacity to accommodate existing and new customer demand and a regulated return on the Company's investment. Accordingly, distribution revenues are influenced by distribution rates, the cost of purchased power, and the amount of electricity the Company distributes. Distribution revenues also include ancillary distribution service revenues, such as fees related to the joint use of Hydro One's distribution poles by the telecommunications and cable television industries, as well as miscellaneous revenues such as charges for late payments.

Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of the electricity purchased by the Company for delivery to customers within Hydro One's distribution service territory. These costs comprise the wholesale commodity cost of energy, in addition to wholesale market service and transmission charges levied by the IESO. Hydro One passes the cost of electricity that it delivers to its customers, and is therefore not exposed to wholesale electricity commodity price risk.

Operation, Maintenance and Administration Costs

Operation, maintenance and administration (OM&A) costs are incurred to support the operation and maintenance of the transmission and distribution systems, and other costs such as property taxes related to transmission and distribution lines, stations and buildings. Transmission OM&A costs are incurred to sustain the Company's high-voltage transmission stations, lines and rights-of-way, and include preventive and corrective maintenance costs related to power equipment, overhead transmission lines, transmission station sites, and forestry control to maintain safe distance between line spans and trees. Distribution OM&A costs are required to maintain the Company's low-voltage distribution system, and include costs related to distribution line clearing and forestry control to reduce power outages caused by trees, line maintenance and repair, as well as land assessment and remediation. Hydro One manages its costs through ongoing efficiency and productivity initiatives, while continuing to complete planned work programs associated with the development and maintenance of its transmission and distribution networks.

Depreciation and Amortization

Depreciation and amortization costs relate primarily to depreciation of the Company's property, plant and equipment, and amortization of certain intangible assets and regulatory assets. Depreciation and amortization also includes the costs incurred to remove property, plant and equipment where no asset retirement obligations have been recorded on the balance sheet.

Financing Charges

Financing charges relate to the Company's financing activities, and include interest expense on the Company's long-term debt and short-term borrowings, gains and losses on interest rate swap agreements, net of interest earned on short-term investments. A portion of financing charges incurred by the Company is capitalized to the cost of property, plant and equipment associated with the periods during which such assets are under construction before being placed in-service.

Income Taxes

Hydro One and its subsidiaries were exempt from regular Canadian federal and Ontario income tax (Federal Tax Regime) and instead paid an equivalent amount referred to as payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC) under the *Electricity Act* (PILs Regime) until October 2015. Since then, Hydro One and its subsidiaries have been subject to the Federal Tax Regime.

Results of Operations

Net Income

Net income attributable to common shareholders for the year ended December 31, 2016 was $721 million, an increase of 4.5% from the prior year. Earnings were positively affected by lower OM&A and higher revenues net of purchased power. These positive effects were partly offset by non-recurring items related to the Company's IPO in 2015, namely an increase in the effective tax rate primarily driven by IPO-related tax benefit of $19 million recorded in 2015 and divestiture of Hydro One Brampton Inc. (Hydro One Brampton) in 2015. Excluding these IPO-related effects, net income increased by 10.9%.

Basic EPS and Adjusted Basic EPS

Basic EPS was $1.21 in 2016 (2015 – $1.39). Basic EPS is significantly affected by the weighted average number of shares in issue being different from last year due to the effects of the IPO, and is the most significant reason for the lower EPS compared to last year.

Adjusted Basic EPS, which adjusts for the inconsistent number of shares in issue, was $1.21 in 2016 (2015 – $1.16), driven by increased net income compared to last year. See section "Non-GAAP Measures" for description of Adjusted EPS.

Revenues

Year ended December 31 *(millions of dollars, except as otherwise noted)*	2016	2015	Change
Transmission	1,584	1,536	3.1%
Distribution	4,915	4,949	(0.7%)
Other	53	53	–
	6,552	6,538	0.2%
Transmission volumes: Average monthly Ontario 60-minute peak demand *(MW)*	20,690	20,344	1.7%
Distribution volumes: Electricity distributed to Hydro One customers *(GWh)*	26,289	28,764	(8.6%)

Transmission Revenues

Transmission revenues increased by 3.1% in 2016 primarily due to the following:

- prior year revenues were affected by a regulatory driven reduction of $28 million related to differences between actual and forecast province-wide conservation and demand management savings during 2014, which did not recur in 2016;
- higher average monthly Ontario 60-minute peak demand mainly due to warmer weather in the second and third quarters of 2016, as well as the impact of several extremely cold days that more than offset the overall milder weather in the fourth quarter of 2016; and
- increased OEB-approved transmission rates for 2016.

Distribution Revenues

Distribution revenues decreased by 0.7% in 2016 primarily due to the following:

- the divestiture of Hydro One Brampton in August 2015, which also caused the majority of the decrease in distribution volumes; and
- lower overall energy consumption resulting from milder weather in the first and fourth quarters of 2016; partially offset by
- higher power costs from generators that are passed on to customers, excluding the impact of divestiture of Hydro One Brampton;
- increased OEB-approved distribution rates for 2016; and
- increased revenues due to a rate order related to shared-use revenue.

Operation, Maintenance and Administration Costs

Year ended December 31 *(millions of dollars)*	2016	2015	Change
Transmission	382	414	(7.7%)
Distribution	608	633	(3.9%)
Other	79	88	(10.2%)
	1,069	1,135	(5.8%)

Transmission OM&A Costs

Transmission OM&A decreased by 7.7% in 2016 primarily due to lower project cost and inventory write-downs coupled with lower activity related to transformer equipment refurbishments and stations maintenance.

Distribution OM&A Costs

Distribution OM&A decreased by 3.9% in 2016 primarily due to the following:

- decrease in bad debt expense including the impact of revised estimates of uncollectible accounts;
- the divestiture of Hydro One Brampton in August 2015;
- lower support services costs; and
- lower costs associated with underground distribution cable locates; partially offset by
- higher volume of vegetation management activities.

Other OM&A Costs

Other OM&A decreased by 10.2% in 2016 primarily due to lower costs relating to the integration of acquired local distribution companies and lower consulting costs.

Depreciation and Amortization

The increase of $19 million or 2.5% in depreciation and amortization costs for 2016 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Financing Charges

The increase of $17 million or 4.5% in financing charges for 2016 was mainly due to the following:

- an increase in interest expense on long-term debt mainly due to the increase in weighted average long-term debt balance outstanding during the year, partially offset by a decrease in the weighted average interest rate for long-term debt; and
- an increase in interest expense on short-term notes mainly due to the increase in weighted average short-term notes balance outstanding during the year, as well as an increase in the weighted average interest rate for short-term notes.

Income Tax Expense

Income tax expense in 2016 increased by $34 million compared to 2015, and the Company realized an effective tax rate of approximately 15.7% in 2016, compared to approximately 12.8% realized in 2015. The increase in the tax expense is primarily due to the effect of an IPO-related positive tax adjustment of $19 million in 2015, coupled with higher income before taxes in 2016.

Common Share Dividends

In 2016, the Company declared and paid cash dividends to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount *(millions of dollars)*
February 11, 2016	March 17, 2016	March 31, 2016	$0.34[1]	202
May 5, 2016	June 14, 2016	June 30, 2016	$0.21	125
August 11, 2016	September 14, 2016	September 30, 2016	$0.21	125
November 10, 2016	December 14, 2016	December 30, 2016	$0.21	125
				577

[1] This was the first common share dividend declared by the Company following the completion of its initial public offering in November 2015. The $0.34 per share dividend included $0.13 for the post-IPO period from November 5 to December 31, 2015, and $0.21 for the quarter ended March 31, 2016.

Following the conclusion of the fourth quarter of 2016, the Company declared a cash dividend to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount *(millions of dollars)*
February 9, 2017	March 14, 2016	March 31, 2017	$0.21	125

Divestiture of Hydro One Brampton

On August 31, 2015, a dividend was paid to the Province of Ontario (Province) by transferring to a company wholly owned by the Province all of the issued and outstanding shares of Hydro One Brampton and inter-company indebtedness owed to Hydro One Inc. by Hydro One Brampton. Hydro One's 2015 consolidated results of operations include the results of Hydro One Brampton up to August 31, 2015. The following tables present quarterly results of Hydro One Brampton that were included in consolidated results of Hydro One for the year ended December 31, 2015.

Quarter ended *(millions of dollars)*	Mar. 31, 2015	Jun. 30, 2015	Sept. 30, 2015	Dec. 31, 2015	2015 Total
Revenues	125	129	100	–	354
Purchased power	107	111	88	–	306
OM&A	6	6	4	–	16
Depreciation and amortization	5	4	2	–	11
Income tax expense	–	1	(1)	–	–
Net income	7	7	7	–	21
Capital investments	9	11	8	–	28

Selected Annual Financial Statistics

Year ended December 31 *(millions of dollars, except per share amounts)*	2016	2015	2014
Total revenue	6,552	6,538	6,548
Net income attributable to common shareholders	721	690	731
Basic and diluted EPS	$ 1.21	$ 1.39	$ 1.53
Basic and diluted Adjusted EPS	$ 1.21	$ 1.16	$ 1.23
Dividends per common share declared	$ 0.97[1]	$ 1.83	$ 0.56
Dividends per preferred share declared	$ 1.12	$ 1.03	$ 1.38

[1] The $0.97 per share dividends declared in 2016 included $0.13 for the post-IPO period from November 5 to December 31, 2015, and $0.84 for the year ended December 31, 2016.

December 31 *(millions of dollars)*	2016	2015	2014
Total assets	25,351	24,294	22,550
Total non-current financial liabilities	10,078	8,207	8,373

Quarterly Results of Operations

Quarter ended *(millions of dollars, except EPS)*	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015
Revenues	1,614	1,706	1,546	1,686	1,522	1,645	1,563	1,808
Purchased power	858	870	803	896	786	856	838	970
Revenues, net of purchased power	756	836	743	790	736	789	725	838
Net income to common shareholders	128	233	152	208	143	188	131	228
Basic EPS	$ 0.22	$ 0.39	$ 0.26	$ 0.35	$ 0.26	$ 0.39	$ 0.27	$ 0.47
Diluted EPS	$ 0.21	$ 0.39	$ 0.25	$ 0.35	$ 0.26	$ 0.39	$ 0.27	$ 0.47
Basic Adjusted EPS	$ 0.22	$ 0.39	$ 0.26	$ 0.35	$ 0.24	$ 0.32	$ 0.22	$ 0.38
Diluted Adjusted EPS	$ 0.21	$ 0.39	$ 0.25	$ 0.35	$ 0.24	$ 0.32	$ 0.22	$ 0.38

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

Capital Investments

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

The following table presents Hydro One's 2016 and 2015 capital investments:

Year ended December 31 *(millions of dollars)*	2016	2015	Change
Transmission			
Sustaining	750	706	6.2%
Development	156	166	(6.0%)
Other	82	71	15.5%
	988	943	4.8%
Distribution			
Sustaining	384	398	(3.5%)
Development	217	220	(1.4%)
Other	102	93	9.7%
	703	711	(1.1%)
Other	6	9	(33.3%)
Total capital investments	1,697	1,663	2.0%

Transmission Capital Investments

Transmission capital investments increased by $45 million or 4.8% in 2016. Principal impacts on the levels of capital investments included:

- an increased volume of work on overhead line refurbishments and insulator replacements;
- an increased volume of integrated station component replacements to sustain certain aging assets at transmission stations;
- continued work on major local area supply network development projects, such as the Holland Transmission Station, the Hawthorne Transmission Station, and the Toronto Midtown Transmission Reinforcement; and
- increased investments relating to information technology infrastructure and customer programs, enhancement projects, including investments to integrate mobile technology with the Company's existing work management tools; partially offset by
- decreased investments in system enhancement projects, primarily due to completion of certain projects and a difference in timing of work on other projects; and
- completion of the Guelph Area Transmission Refurbishment project.

Distribution Capital Investments

Distribution capital investments decreased by $8 million or 1.1% in 2016. Principal impacts on the levels of capital investments included:

- reduced capital expenditures due to the divestiture of Hydro One Brampton in 2015; and
- a lower volume of work within station refurbishment programs and lower volume of spare transformer purchases; partially offset by
- increased investments related to information technology infrastructure and customer programs together with upgrade and enhancement projects, including investments to integrate mobile technology with the Company's existing work management tools; and
- investments in smart grid technology to mitigate power quality impacts of distributed generation and to improve outage response times.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2016:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To-Date
Development Projects:					
Guelph Area Transmission Refurbishment	Guelph area Southwestern Ontario	Transmission line upgrade	September 2016[1]	$87 million	$86 million
Toronto Midtown Transmission Reinforcement	Toronto Southwestern Ontario	New transmission line	December 2016[2]	$118 million	$113 million
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$73 million	$13 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$192 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	To be determined	To be determined	–
East-West Tie Station Expansion	Northern Ontario	Station expansion	2020	$166 million	–
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2019	$109 million	$83 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$102 million	$68 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2020	$95 million	$15 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2021	$93 million	$28 million

[1] Major portions of the project were completed and placed in-service in September 2016. Work on certain minor portions of the project continues in the first quarter of 2017.

[2] Major portions of the project were completed and placed in-service in December 2016. Work on certain minor portions of the project continues in the first quarter of 2017.

Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the next five years. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework. These estimates differ from the prior year disclosures, reflecting annual increases of $126 million for 2017, $113 million for 2018, $239 million for 2019, and $360 million for 2020. These future capital investments reflect management's best estimates and, as applicable, projections included in rate filings currently in process. These projections and the timing of expenditures are in large part subject to approval by the OEB, and will be adjusted going forward as appropriate to reflect rate decisions by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2017 to 2021, by business segment:

(millions of dollars)	2017	2018	2019	2020	2021
Transmission	1,086	1,132	1,217	1,278	1,486
Distribution	648	647	771	735	749
Other	12	9	8	6	8
Total capital investments	1,746	1,788	1,996	2,019	2,243

The following table summarizes Hydro One's annual projected capital investments for 2017 to 2021, by category:

(millions of dollars)	2017	2018	2019	2020	2021
Sustaining	1,107	1,165	1,219	1,327	1,546
Development	414	400	484	487	490
Other[1]	225	223	293	205	207
Total capital investments	1,746	1,788	1,996	2,019	2,243

[1] "Other" capital expenditures consist of special projects, such as those relating to information technology.

Summary Of Sources And Uses Of Cash

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

Year ended December 31 *(millions of dollars)*	**2016**	2015
Cash provided by (used in) operating activities	**1,656**	(1,248)
Cash provided by financing activities	**161**	2,954
Cash used in investing activities	**(1,861)**	(1,712)
Decrease in cash and cash equivalents	**(44)**	(6)

Primary factors behind the increase in cash provided by operating activities

The increase in cash provided by operating activities is primarily due to a deferred tax recovery of $2.8 billion recorded in 2015 that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime.

Primary factors behind the decrease in cash provided by financing activities

Sources of cash

- The Company received $2.3 billion proceeds from issuance of long-term debt in 2016, compared to $350 million received last year.
- The Company received $3,031 million proceeds from issuance of short-term notes in 2016, compared to $2,891 million received last year.
- In 2015, the Company received $2.6 billion proceeds from common shares issued to the Province prior to the completion of the initial public offering (IPO).

Uses of cash

- Dividends paid in 2016 were $596 million, consisting of $577 million common share dividends and $19 million preferred share dividends, compared to $888 million paid in 2015. 2015 dividends consisted of $75 million common share dividends, $13 million preferred share dividends, as well as an $800 million special dividend paid to the Province prior to the completion of the IPO.
- The Company repaid $4,053 million of short-term notes, compared to $1,400 million repaid last year.
- The Company repaid $502 million of long-term debt in 2016 compared to $585 million repaid last year.

Primary factors behind the increase in cash used in investing activities

Uses of cash

- Capital expenditures were $29 million higher in 2016, primarily due to increased transmission capital investments consistent with the Company's ongoing capital investment program.
- In 2016, the Company paid $226 million to acquire Great Lakes Power, compared to a total of $90 million paid in 2015 to acquire Haldimand County Utilities Inc. (Haldimand Hydro) and Woodstock Hydro Holdings Inc. (Woodstock Hydro).
- In August 2015, an investment of $53 million was made in Hydro One Brampton prior to its divestiture to the Province.

Liquidity and Financing Strategy

Short-term liquidity is provided through funds from operations, Hydro One Inc.'s commercial paper program, and the Company's consolidated bank credit facilities. Under the commercial paper program, Hydro One Inc. is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At December 31, 2016, Hydro One Inc. had $469 million in commercial paper borrowings outstanding, compared to $1,491 million outstanding at December 31, 2015. In addition, the Company and Hydro One Inc. have revolving bank credit facilities totalling $2,550 million maturing in 2021. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At December 31, 2016, the Company's long-term debt in the principal amount of $10,671 million included $10,523 million long-term debt issued under Hydro One Inc.'s Medium Term Note (MTN) Program and long-term debt in the principal amount of $148 million held by Great Lakes Power. At December 31, 2016, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2017 and 2064, and at December 31, 2016, had an average term to maturity of approximately 15.9 years and a weighted average coupon of 4.3%.

On March 30, 2016, Hydro One filed a final universal short form base shelf prospectus (Universal Base Shelf Prospectus) with securities regulatory authorities in Canada. The Universal Base Shelf Prospectus allows Hydro One to offer, from time to time in one or more public offerings, up to $8.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on April 30, 2018. Hydro One filed the Universal Base Shelf Prospectus in part to facilitate the secondary offerings of outstanding shares of the Company by the Province, and to provide the Company with increased financing flexibility going forward. In 2016, Hydro One completed a secondary offering of a portion of its common shares previously owned by the Province. See section "Other Developments – Change in Hydro One Ownership Structure" for details of this transaction. Upon closing of the transaction, $6,030 million remained available under the Universal Base Shelf Prospectus.

At December 31, 2016, the Company and Hydro One Inc. were in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

At December 31, 2016, Hydro One's corporate credit ratings were as follows:

Rating Agency	Corporate Credit Rating
Standard & Poor's Rating Services (S&P)	A

Hydro One has not obtained a credit rating in respect of any of its securities. An issuer rating from S&P is a forward-looking opinion about an obligor's overall creditworthiness. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due but it does not apply to any specific financial obligation. An obligor with a long-term credit rating of 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories.

The rating above is not a recommendation to purchase, sell or hold any of Hydro One's securities and does not comment on the market price or suitability of any of the securities for a particular investor. There can be no assurance that the rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn entirely by S&P at any time in the future. Hydro One has made, and anticipates making, payments to S&P pursuant to agreements entered into with S&P in respect of the rating assigned to Hydro One and expects to make payments to S&P in the future to the extent it obtains a rating specific to any of its securities.

At December 31, 2016, Hydro One Inc.'s long-term and short-term debt ratings were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited	R-1 (low)	A (high)
Moody's Investors Service	Prime-2	A3
S&P	A-1	A

Effect of Interest Rates

The Company is exposed to fluctuations of interest rates as its regulated return on equity (ROE) is derived using a formulaic approach that takes into account changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. See section "Risk Management and Risk Factors – Risks Relating to Hydro One's Business – Market, Financial Instrument and Credit Risk" for more details.

Pension Plan

In 2016, Hydro One contributed approximately $108 million to its pension plan, compared to contributions of approximately $177 million in 2015, and incurred $116 million in net periodic pension benefit costs, compared to $163 million incurred in 2015.

In June 2016, Hydro One Inc. filed an actuarial valuation of its Pension Plan as at December 31, 2015. Based on this valuation and 2016 levels of pensionable earnings, the 2016 annual employer contributions have decreased by approximately $72 million from $180 million as estimated at December 31, 2015, primarily due to improvements in the funded status of the plan and future actuarial assumptions. The decrease also reflects the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan. The updated actuarial valuation resulted in a $25 million decrease in 2016 revenue with a corresponding decrease in OM&A costs, as the lower pension contributions will be returned to customers through the pension cost variance deferral account in future rate applications. The Company estimates that total pension contributions for 2017 and 2018 will be approximately $105 million and $102 million, respectively.

The Company's pension benefits obligation is impacted by various assumptions and estimates, such as discount rate, rate of return on plan assets, rate of cost of living increase and mortality assumptions. A full discussion of the significant assumptions and estimates can be found in the section "Critical Accounting Estimates – Employee Future Benefits".

Other Obligations

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

December 31, 2016 *(millions of dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	10,671	602	1,484	1,156	7,429
Long-term debt – interest payments	8,145	456	827	754	6,108
Short-term notes payable	469	469	–	–	–
Pension contributions[1]	207	105	102	–	–
Environmental and asset retirement obligations	243	27	51	65	100
Outsourcing agreements	374	165	196	4	9
Operating lease commitments	42	11	16	13	2
Long-term software/meter agreement	73	17	33	18	5
Total contractual obligations	20,224	1,852	2,709	2,010	13,653
Other commercial commitments *(by year of expiry)*					
Credit facilities[2]	2,550	–	–	2,550	–
Letters of credit[3]	174	174	–	–	–
Guarantees[4]	330	330	–	–	–
Total other commercial commitments	3,054	504	–	2,550	–

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2017 and 2018 minimum pension contributions are based on an actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings.

[2] On August 15, 2016, Hydro One Inc. terminated its credit facilities totalling $2.3 billion maturing in June 2020 and October 2018, and entered into a new $2.3 billion credit facility maturing in June 2021. On November 7, 2016, the maturity date of Hydro One's $250 million credit facility was extended from November 2020 to November 2021.

[3] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, and letters of credit totalling $24 million provided as prudential support.

[4] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

Regulation

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its equity invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Year(s)	Type	Status
Electricity Rates			
Hydro One Networks	2015-2016	Transmission – Cost-of-service	OEB decision received
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision pending
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
Great Lakes Power	2017	Transmission – Cost-of-service	OEB decision pending
Mergers Acquisitions Amalgamations and Divestitures			
Great Lakes Power	n/a	Acquisition	OEB decision received
Orillia Power	n/a	Acquisition	OEB decision pending
Leave to Construct			
Supply to Essex County Transmission Reinforcement Project	n/a	Section 92	OEB decision received

Hydro One has obtained revenue requirement approvals from the OEB, subject to certain annual adjustments, for Hydro One Networks' transmission business through 2016, for B2M LP through 2019, and for Hydro One Networks' distribution business to the end of 2017. The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2016	9.19% (A)	$10,040 million	Approved in January 2015	Approved in January 2016
	2017	8.78% (A)	$10,554 million	Filed in May 2016	To be filed in 2017 Q1
	2018	8.78% (F)	$11,226 million	Filed in May 2016	To be filed in 2017 Q4
B2M LP	2016	9.19% (A)	$516 million	Approved in December 2015	Approved in January 2016
	2017	8.78% (A)	$509 million	Approved in December 2015	Filed in December 2016
	2018	8.78% (F)	$502 million	Approved in December 2015	To be filed in 2017 Q4
	2019	8.78% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
Great Lakes Power	2017	9.19% (F)	$218 million	Filed in December 2016	Filed in December 2016
Distribution					
Hydro One Networks	2016	9.19% (A)	$6,863 million	Approved in March 2015	Approved in April 2015
	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016

Hydro One Networks

On May 31, 2016, Hydro One Networks filed a cost-of-service application with the OEB for 2017 and 2018 transmission rates. The application seeks approval of rate base of $10,554 million for 2017 and $11,226 million for 2018. In October 2016, the OEB issued updated cost of capital parameters for rates effective in 2017, including an updated 2017 allowed ROE of 8.78%. The application also lays out a planned transmission capital investment program for the five-year period ending on December 31, 2021, with investments in capital spending primarily to address reliability, safety and customer needs, in a cost-effective manner. Management expects that a decision will be received in the first half of 2017, and that new rates will be retroactive to January 1, 2017. Future transmission rate applications are anticipated to be filed under the OEB's incentive-based regulatory framework.

Hydro One Networks plans to submit an application for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework in the first quarter of 2017.

B2M LP

On January 14, 2016, the OEB issued its Decision and Rate Order approving the B2M LP revenue requirement recovery through the 2016 Uniform Transmission Rates. On December 1, 2016, B2M LP filed a Draft Rate Order with a revised 2017 revenue requirement of $34 million, reflecting updated 2017 cost of capital parameters issued by the OEB in October 2016.

Other Regulatory Developments

OEB Pension and Other Post-Employment Benefits (OPEB) Generic Hearing

In 2015, the OEB began a consultation process to examine pensions and OPEBs in rate-regulated utilities, with the objectives of developing standard principles to guide its review of pension and OPEB related costs in the future, and to establish specific requirements for applications and appropriate and consistent regulatory mechanisms for cost recovery. Hydro One and other stakeholders filed written submissions with respect to initial OEB questions intended to solicit views on the key issues of interest to the OEB. Following a stakeholder forum in July 2016, updated written submissions were filed with the OEB in September 2016. It is anticipated that subsequent to the OEB's review of the updated written submissions, the OEB will outline principles to guide its review of pension and OPEB related costs in the future, and provide further guidance on application requirements and regulatory mechanisms for cost recovery.

Other Developments

Change in Hydro One Ownership Structure

In November 2015, Hydro One and the Province completed an IPO on the Toronto Stock Exchange of approximately 89.3 million common shares of Hydro One, representing 15% of the Province's ownership position. Prior to the completion of the IPO, Hydro One and its subsidiary, Hydro One Inc., completed a series of transactions (Pre-IPO Transactions) that resulted in, among other things, the acquisition by Hydro One of all of the issued and outstanding shares of Hydro One Inc. from the Province and the issuance of new common shares and preferred shares of Hydro One to the Province. Both Hydro One and Hydro One Inc. are reporting issuers. In April 2016, the Province completed a secondary offering of 83.3 million common shares of Hydro One on the Toronto Stock Exchange. Hydro One did not receive any of the proceeds from either of the sales of common shares by the Province. At December 31, 2016, the Province directly holds approximately 70.1% of Hydro One's total issued and outstanding common shares.

Class Action Lawsuit

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities Inc., and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. A certification motion in the class action is pending. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

Acquisitions

Integration of Haldimand Hydro and Woodstock Hydro

In 2015, the Company acquired Haldimand Hydro and Woodstock Hydro, two Ontario-based local distribution companies. In September 2016, the Company successfully completed the integration of both entities, including the integration of employees, customer and billing information, business processes, and operations.

Acquisition of Great Lakes Power

On October 31, 2016, following receipt of regulatory approval of the transaction by the OEB, Hydro One completed the acquisition of Great Lakes Power, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario. The total purchase price for Great Lakes Power was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. On January 16, 2017, Great Lakes Power's name was changed to Hydro One Sault Ste. Marie LP.

On December 23, 2016, Great Lakes Power filed an application for 2017 rates, requesting an increase to the approved 2016 revenue requirement of 1.9%, resulting in an updated revenue requirement of $41 million.

Acquisition of Orillia Power

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power), an electricity distribution company located in Simcoe County, Ontario, for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments. The acquisition is subject to regulatory approval by the OEB.

Hydro One Work Force

Hydro One has a skilled and flexible work force of approximately 5,500 regular employees and over 2,000 non-regular employees province-wide, comprising a mix of skilled trades, engineering, professional, managerial and executive personnel. Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for variable workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to flexibly utilize highly trained and appropriately skilled workers on a project-by-project and seasonal basis.

The following table sets out the number of Hydro One employees as at December 31, 2016.

	Regular Employees	Non-Regular Employees	Total
Power Workers' Union (PWU)	3,470	698[1]	4,168
The Society of Energy Professionals (Society)	1,365	44	1,409
Canadian Union of Skilled Workers (CUSW) and construction building trade unions[2]	–	1,275	1,275
Total employees represented by unions	4,835	2,017	6,852
Management and non-represented employees	659	28	687
Total employees	5,494	2,045	7,539

[1] Includes 528 non-regular "hiring hall" employees covered by the PWU agreement.

[2] Employees are jointly represented by both unions. The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA).

Share-based Compensation

During 2016, the Company granted awards under its Long-term Incentive Plan, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled. At December 31, 2016, 230,600 PSUs and 254,150 RSUs were outstanding. No long-term incentive awards were granted during 2015.

Non-Gaap Measures

Funds from Operations (FFO) and Adjusted FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Adjusted FFO is defined as FFO, adjusted for the impact of the deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime. Management believes that FFO and Adjusted FFO are helpful as supplemental measures of the Company's operating cash flows as they exclude timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders, and, in the case of Adjusted FFO, the impact of the IPO-related deferred income tax asset. As such, these measures provide consistent measures of the cash generating performance of the Company's assets.

The following table presents the reconciliation of net cash from operating activities to FFO and Adjusted FFO:

Year ended December 31 *(millions of dollars)*	**2016**	2015
Net cash from (used in) operating activities	**1,656**	(1,248)
Changes in non-cash balances related to operations	**(134)**	(213)
Preferred share dividends	**(19)**	(13)
Distributions to noncontrolling interest	**(9)**	(5)
FFO	**1,494**	(1,479)
Less: Deferred income tax asset[1]	**–**	(2,810)
Adjusted FFO	**1,494**	1,331

[1] Impact of deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime.

Adjusted EPS

The following basic and diluted Adjusted EPS has been prepared by management on a supplementary basis which assumes that the total number of common shares outstanding was 595,000,000 in each of the years ended December 31, 2016 and 2015. The supplementary pro forma disclosure is used internally by management subsequent to the IPO of the Company's common shares in November 2015 to assess the Company's performance and is considered useful because it eliminates the impact of a different and non-comparable number of shares outstanding and held by the Province prior to the IPO. Adjusted EPS is considered an important measure and management believes that presenting it consistently for all periods based on the number of outstanding shares on, and subsequent to, the IPO provides users with a comparative basis to evaluate the operations of the Company.

Year ended December 31	**2016**	2015
Net income attributable to common shareholders *(millions of dollars)*	**721**	690
Pro forma weighted average number of common shares		
Basic	**595,000,000**	595,000,000
Effect of dilutive stock-based compensation plans	**1,700,823**	94,691
Diluted	**596,700,823**	595,094,691
Adjusted EPS		
Basic	**$ 1.21**	$ 1.16
Diluted	**$ 1.21**	$ 1.16

Adjusted Net Cash from Operating Activities

Adjusted net cash from operating activities is defined as net cash from operating activities, adjusted for the impact of the deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime. Management believes that this measure is helpful as a supplemental measure of the Company's net cash from operating activities as it excludes the impact of the IPO-related deferred income tax asset. As such, adjusted net cash from operating activities provides a consistent measure of the Company's cash from operating activities compared to prior periods.

The following table presents the reconciliation of net cash from operating activities to adjusted net cash from operating activities:

Year ended December 31 *(millions of dollars)*	2016	2015
Net cash from (used in) operating activities	1,656	(1,248)
Less: Deferred income tax asset[1]	–	(2,810)
Adjusted net cash from operating activities	1,656	1,562

[1] Impact of deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime.

To the extent that adjusted net income is used in future continuous disclosure documents of Hydro One, it will be defined as net income, adjusted for certain items, including non-recurring items and other one-time items that management does not consider to be reflective of the operating performance of the Company. No such adjustments to net income are presented in this MD&A. Management believes that this measure will be helpful in assessing the Company's financial and operating performance in the future.

FFO, adjusted FFO, adjusted basic and diluted EPS, adjusted net cash from operating activities, and adjusted net income are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

Related Party Transactions

The Province is the majority shareholder of Hydro One. The IESO, Ontario Power Generation Inc. (OPG), OEFC, OEB, and Hydro One Brampton are related parties to Hydro One because they are controlled or significantly influenced by the Province. The following is a summary of the Company's related party transactions during the year ended December 31, 2016:

		Year ended December 31	
		2016	2015
Related Party	Transaction	*(millions of dollars)*	
Province[1]	Dividends paid	451	888
	Common shares issued[2]	–	2,600
	IPO costs subsequently reimbursed by the Province[3]	–	7
IESO	Power purchased	2,096	2,318
	Revenues for transmission services	1,549	1,548
	Distribution revenues related to rural rate protection	125	127
	Distribution revenues related to the supply of electricity to remote northern communities	32	32
	Funding received related to Conservation and Demand Management programs	63	70
OPG	Power purchased	6	11
	Revenues related to provision of construction and equipment maintenance services	5	7
	Costs expensed related to the purchase of services	1	1
OEFC	Payments in lieu of corporate income taxes[4]	–	2,933
	Power purchased from power contracts administered by the OEFC	1	6
	Indemnification fee paid (terminated effective October 31, 2015)	–	8
OEB	OEB fees	11	12
Hydro One Brampton[1]	Revenues from management, administrative and smart meter network services	3	1

[1] On August 31, 2015, Hydro One Inc. completed the spin-off of its subsidiary, Hydro One Brampton, to the Province.
[2] On November 4, 2015, Hydro One issued common shares to the Province for proceeds of $2.6 billion.
[3] In 2015, Hydro One incurred certain IPO related expenses totalling $7 million, which were subsequently reimbursed to the Company by the Province.
[4] In 2015, Hydro One made PILs to the OEFC totalling $2.9 billion, including departure tax of $2.6 billion.

At December 31, 2016, the amounts due from and due to related parties as a result of the transactions described above were $158 million and $147 million, compared to $191 million and $138 million at December 31, 2015, respectively. At December 31, 2016, included in amounts due to related parties were amounts owing to the IESO in respect of power purchases of $143 million, compared to $134 million at December 31, 2015.

Risk Management and Risk Factors

Risks Relating to Hydro One's Business

Regulatory Risks and Risks Relating to Hydro One's Revenues

Risks Relating to Obtaining Rate Orders

The Company is subject to the risk that the OEB will not approve the Company's transmission and distribution revenue requirements requested in outstanding or future applications for rates. Rate applications for revenue requirements are subject to the OEB's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the OEB will permit Hydro One to recover all costs actually incurred, costs of debt and income taxes, or to earn a particular ROE. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, may materially adversely affect: Hydro One's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Company. In addition, there is no assurance that the Company will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Risks Relating to Actual Performance Against Forecasts

The Company's ability to recover the actual costs of providing service and earn the allowed ROE depends on the Company achieving its forecasts established and approved in the rate-setting process. Actual costs could exceed the approved forecasts if, for example, the Company incurs operations, maintenance, administration, capital and financing costs above those included in the Company's approved revenue requirement. The inability to obtain acceptable rate decisions or to recover any significant difference between forecast and actual expenses could materially adversely affect the Company's financial condition and results of operations.

Further, the OEB approves the Company's transmission and distribution rates based on projected electricity load and consumption levels, among other factors. If actual load or consumption materially falls below projected levels, the Company's revenue and net income for either, or both, of these businesses could be materially adversely affected. Also, the Company's current revenue requirements for these businesses are based on cost and other assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in the Company's costs.

The Company is subject to risk of revenue loss from other factors, such as economic trends and weather conditions that influence the demand for electricity. The Company's overall operating results may fluctuate substantially on a seasonal and year-to-year basis based on these trends and weather conditions. For instance, a cooler than normal summer or warmer than normal winter may reduce demand for electricity below that forecast by the Company, causing a decrease in the Company's revenues from the same period of the previous year. The Company's load could also be negatively affected by successful Conservation and Demand Management programs whose results exceed forecasted expectations.

Risks Relating to Rate-Setting Models for Transmission and Distribution

The OEB approves and periodically changes the ROE for transmission and distribution businesses. The OEB may in the future decide to reduce the allowed ROE for either of these businesses, modify the formula or methodology it uses to determine the ROE, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company.

The OEB's recent Custom Incentive Rate-setting model requires that the term of a custom rate application be a minimum five-year period. There are risks associated with forecasting key inputs such as revenues, operating expenses and capital, over such a long period. For instance, if unanticipated capital expenditures arise that were not contemplated in the Company's most recent rate decision, the Company may be required to incur costs that may not be recoverable until a future period or not recoverable at all in future rates. This could have a material adverse effect on the Company.

After rates are set as part of a part of a Custom Incentive Rate application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital (including ROE), working capital allowance or sales volumes. If there were an increase in interest rates over the period of a rate decision and no corresponding changes were permitted to the

Company's allowed cost of capital (including ROE), then the result could be a decrease in the Company's financial performance.

To the extent that the OEB approves an In-Service Variance Account for the transmission and/or distribution businesses, and should the Company fail to meet the threshold levels of in-service capital, the OEB may reclaim a corresponding portion of the Company's revenues.

Risks Relating to Capital Expenditures

In order to be recoverable, capital expenditures require the approval of the OEB, either through the approval of capital expenditure plans, rate base or revenue requirements for the purposes of setting transmission and distribution rates, which include the impact of capital expenditures on rate base or cost of service. There can be no assurance that all capital expenditures incurred by Hydro One will be approved by the OEB. Capital cost overruns may not be recoverable in transmission or distribution rates. The Company could incur unexpected capital expenditures in maintaining or improving its assets, particularly given that new technology may be required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. There is risk that the OEB may not allow full recovery of such expenditures in the future. To the extent possible, Hydro One aims to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

Any future regulatory decision by the OEB to disallow or limit the recovery of any capital expenditures would lead to a lower than expected approved revenue requirement or rate base, potential asset impairment or charges to the Company's results of operations, any of which could have a material adverse effect on the Company.

Risks Relating to Deferred Tax Asset

As a result of leaving the PILs Regime and entering the Federal Tax Regime in connection with the IPO of the Company, Hydro One recorded a deferred tax asset due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. Management believes this will result in annual net cash savings over at least the next five years due to the reduction of cash income taxes payable by Hydro One associated primarily with a higher capital cost allowance. There is a risk that, in current or future rate applications, the OEB will reduce the Company's revenue requirement by all or a portion of those net cash savings. If the OEB were to reduce the Company's revenue requirement in this manner, it could have a material adverse effect on the Company.

Risks Relating to Other Applications to the OEB

The Company is also subject to the risk that it will not obtain required regulatory approvals for other matters, such as leave to construct applications, applications for mergers, acquisitions, amalgamations and divestitures, and environmental approvals. Decisions to acquire or divest other regulated businesses licensed by the OEB are subject to OEB approval. Accordingly, there is the risk that such matters may not be approved or that unfavourable conditions will be imposed by the OEB.

First Nations and Métis Claims Risk

Some of the Company's current and proposed transmission and distribution assets are or may be located on reserve (as defined in the *Indian Act* (Canada); Reserve) lands, and lands over which First Nations and Métis have Aboriginal, treaty, or other legal claims. Some First Nations and Métis leaders, communities, and their members have made assertions related to sovereignty and jurisdiction over Reserve lands and traditional territories and are increasingly willing to assert their claims through the courts, tribunals, or by direct action. These claims and/or settlement of these claims could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations, including the development of current and future projects.

The Company's operations and activities may give rise to the Crown's duty to consult and potentially accommodate First Nations and Métis communities. Procedural aspects of the duty to consult may be delegated to the Company by the Province or the federal government. A perceived failure by the Crown to sufficiently consult a First Nations or Métis community, or a perceived failure by the Company in relation to delegated consultation obligations, could result in legal challenges against the Crown or the Company, including judicial review or injunction proceedings, or could potentially result in direct action against the Company by a community or its citizens. If this occurs, it could disrupt or delay the Company's operations and activities, including current and future projects, and have a material adverse effect on the Company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to assets located on Reserves. The transfer of title to these assets did not occur because authorizations originally granted by the federal government for the construction and operation of these assets on Reserves could not be transferred without required consent. In several cases, the authorizations had either expired or had never been issued.

Currently, the Ontario Electricity Financial Corporation holds legal title to these assets and it is expected that the Company will manage them until it has obtained permits to complete the title transfer. To occupy Reserves, the Company must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the Ontario Electricity Financial Corporation and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal government (presently Indigenous Affairs and Northern Development Canada) issuing a permit. For transmission assets, the Company must negotiate terms of payment. It is difficult to predict the aggregate amount that the Company may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. If the Company cannot reach satisfactory agreements with the relevant First Nation to obtain federal permits, it may have to relocate these assets to other locations and restore the lands at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. In either case, the costs relating to these assets could have a material adverse effect on the Company if the costs are not recoverable in future rate orders.

Compliance with Laws and Regulations

Hydro One must comply with numerous laws and regulations affecting its business, including requirements relating to transmission and distribution companies, environmental laws, employment laws and health and safety laws. The failure of the Company to comply with these laws could have a material adverse effect on the Company's business. See also "– Health, Safety and Environmental Risk".

For example, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licences, with codes and rules issued by the OEB, and with other regulatory requirements, including regulations of the National Energy Board. In Ontario, the Market Rules issued by the IESO require the Company to, among other things, comply with the reliability standards established by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council, Inc. (NPCC). The incremental costs associated with compliance with these reliability standards are expected to be recovered through rates, but there can be no assurance that the OEB will approve the recovery of all of such incremental costs. Failure to obtain such approvals could have a material adverse effect on the Company.

There is the risk that new legislation, regulations, requirements or policies will be introduced in the future. These may require Hydro One to incur additional costs, which may or may not be recovered in future transmission and distribution rates.

Risk of Natural and Other Unexpected Occurrences

The Company's facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including but not limited to cyber and physical terrorist type attacks, events which originate from third-party connected systems, or any other potentially catastrophic events. The Company's facilities may not withstand occurrences of this type in all circumstances. The Company does not have insurance for damage to its transmission and distribution wires, poles and towers located outside its transmission and distribution stations resulting from these or other events. Where insurance is available for other assets, such insurance coverage may have deductibles, limits and/or exclusions. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas. The Company could also be subject to claims for damages caused by its failure to transmit or distribute electricity.

Risk Associated with Information Technology Infrastructure and Data Security

The Company's ability to operate effectively in the Ontario electricity market is, in part, dependent upon it developing, maintaining and managing complex information technology systems which are employed to operate and monitor its transmission and distribution facilities, financial and billing systems and other business systems. The Company's increasing reliance on information systems and expanding data networks increases its exposure to information security threats. The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC. These include standards relating to cyber-security and information technology, which only apply to certain of the Company's assets (generally being those whose failure could impact the functioning of the bulk electricity system). The Company may maintain different or lower levels of information technology security for its assets that are not subject to these mandatory standards. The Company must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information and information regarding consumers, wholesalers, generators and retailers.

Cyber-attacks or unauthorized access to corporate and information technology systems could result in service disruptions and system failures, which could have a material adverse effect on the Company, including as a result of a failure to provide electricity to customers. Due to operating critical infrastructure, Hydro One may be at greater risk of cyber-attacks from third parties (including state run or controlled parties) that could impair or incapacitate its assets. In addition, in the normal course of its operations, the Company collects, uses, processes and stores information, which could be exposed in the event of a cyber-security incident or other unauthorized access, such as information about customers, suppliers, counterparties and employees.

Security and system disaster recovery controls are in place; however, there can be no assurance that there will not be system failures or security breaches or that such threats would be detected or mitigated on a timely basis. Upon occurrence and detection, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on the Company.

Work Force Demographic Risk

By the end of 2016, approximately 22% of the Company's employees who are members of the Company's defined benefit pension plan were eligible for retirement under that plan, and by the end of 2017, up to approximately 23% could be eligible. These percentages are not evenly spread across the Company's work force, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During each of 2016 and 2015, approximately 3% of the Company's work force elected to retire. Accordingly, the Company's continued success will be tied to its ability to continue to attract and retain sufficient qualified staff to replace the capability lost through retirements and to meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry to be highly competitive in the future. Many of the Company's current employees and many of the potential employees it would seek in the future possess skills and experience that would also be highly sought after by other organizations inside and outside the electricity sector. The failure to attract and retain qualified personnel for Hydro One's business could have a material adverse effect on the Company.

Labour Relations Risk

The substantial majority of the Company's employees are represented by either the PWU or the Society. Over the past several years, significant effort has been expended to increase Hydro One's flexibility to conduct operations in a more cost-efficient manner. Although the Company has achieved improved flexibility in its collective agreements, the Company may not be able to achieve further improvements. The Company reached an agreement with the PWU for a renewal collective agreement with a three-year term, covering the period from April 1, 2015 to March 31, 2018 and an early renewal collective agreement with the Society with a three-year term, covering the period from April 1, 2016 to March 31, 2019. The Company also reached a renewal collective agreement with the Canadian Union of Skilled Workers for a three-year term, covering the period from May 1, 2014 to April 30, 2017. Additionally, the EPSCA and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a five-year term, covering the period from May 1, 2015 to April 30, 2020. Future negotiations with unions present the risk of a labour disruption and the ability to sustain the continued supply of energy to customers. The Company also faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. In addition, in the event of a labour dispute, the Company could face operational risk related to continued compliance with its requirements of providing service to customers. Any of these could have a material adverse effect on the Company.

Risk Associated with Arranging Debt Financing

The Company expects to borrow to repay its existing indebtedness and to fund a portion of capital expenditures. Hydro One Inc. has substantial debt principal repayments, including $602 million in 2017, $753 million in 2018, and $731 million in 2019. In addition, from time to time, the Company may draw on its syndicated bank lines and or issue short-term debt under Hydro One Inc.'s $1.5 billion commercial paper program which would mature within approximately one year of issuance. The Company also plans to incur continued material capital expenditures for each of 2017 and 2018. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of the Company's existing indebtedness and capital expenditures. The Company's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, the Company's results of operations and financial position, market conditions, the ratings assigned to its debt securities by credit rating agencies, an inability of the Corporation to comply with its debt covenants, and general economic conditions. A downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt. Any failure or inability on the Company's part to borrow the required amounts of debt on satisfactory terms could impair its ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on the Company.

Market, Financial Instrument and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated ROE is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk or material foreign exchange risk.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company estimates that a decrease of 100 basis points in the combination of the forecasted long-term Government of Canada bond yield and the A-rated utility corporate bond yield spread used in determining its rate of return would reduce the Company's transmission business' 2018 net income by approximately $23 million and its distribution business' 2018 net income by approximately $15 million. The Company periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. Hydro One monitors and minimizes credit risk through various techniques, including dealing with highly rated counterparties, limiting total exposure levels with individual counterparties, entering into agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. The Company is required to procure electricity on behalf of competitive retailers and certain local distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into the Company's service agreements with these retailers in accordance with the OEB's Retail Settlement Code.

The failure to properly manage these risks could have a material adverse effect on the Company.

Risks Relating to Asset Condition and Capital Projects

The Company continually incurs sustainment and development capital expenditures and monitors the condition of its transmission assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution infrastructure. However the lack of real time monitoring of distribution assets increases the risk of distribution equipment failure. The connection of large numbers of generation facilities to the distribution network has resulted in greater than expected usage of some of the Company's equipment. This increases maintenance requirements and may accelerate the aging of the Company's assets.

Execution of the Company's capital expenditure programs, particularly for development capital expenditures, is partially dependent on external factors, such as environmental approvals, municipal permits, equipment outage schedules that accommodate the IESO, generators and transmission-connected customers, and supply chain availability for equipment suppliers and consulting services. There may also be a need for, among other things, *Environmental Assessment Act* (Ontario) approvals, approvals which require public meetings, appropriate engagement with First Nations and Métis communities, OEB approvals of expropriation or early access to property, and other activities. Obtaining approvals and carrying out these processes may also be impacted by opposition to the proposed site of the capital investments. Delays in obtaining required approvals or failure to complete capital projects on a timely basis could materially adversely affect transmission reliability or customers' service quality or increase maintenance costs which could have a material adverse effect on the Company. External factors are considered in the Company's planning process. If the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce network capacity, result in customer interruptions, compromise the reliability of the Company's networks or increase the costs of operating and maintaining these assets. Any of these consequences could have a material adverse effect on the Company.

Increased competition for the development of large transmission projects and legislative changes relating to the selection of transmitters could impact the Company's ability to expand its existing transmission system, which may have an adverse effect on the Company. To the extent that other parties are selected to construct, own and operate new transmission assets, the Company's share of Ontario's transmission network would be reduced.

Health, Safety and Environmental Risk

The Company is subject to provincial health and safety legislation. Findings of a failure to comply with this legislation could result in penalties and reputational risk, which could negatively impact the Company.

The Company is subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject the Company to fines or other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties or governmental orders requiring the Company to take specific actions such as investigating, controlling and remediating the effects of these substances. Contamination of the Company's properties could limit its ability to sell or lease these assets in the future.

In addition, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on the Company's balance sheet. The Company does not have insurance coverage for these environmental expenditures.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases.

Hydro One emits certain greenhouse gases, including sulphur hexafluoride or "SF6". There are increasing regulatory requirements and costs, along with attendant risks, associated with the release of such greenhouse gases, all of which could impose additional material costs on Hydro One.

Any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on the Company.

Pension Plan Risk

Hydro One has the Hydro One Defined Benefit Pension Plan in place for the majority of its employees. Contributions to the pension plan are established by actuarial valuations which are required to be filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2015, and was filed in June 2016, covering a three year period from 2016 to 2018. Hydro One's contributions to its pension plan satisfy, and are expected to satisfy, minimum funding requirements. Contributions beyond 2018 will depend on the funded position of the plan, which is determined by investment returns, interest rates and changes in benefits and actuarial assumptions at that time. A determination by the OEB that some of the Company's pension expenditures are not recoverable through rates could have a material adverse effect on the Company, and this risk may be exacerbated if the amount of required pension contributions increases.

The OEB has begun a consultation process that will examine pensions and other post-employment benefits in regulated utilities. See "– Other Post-Employment and Post-Retirement Benefits Risks". The outcome of this consultation process is uncertain and the Company is unable to assess the impact of the potential changes stemming from the review at this time.

Risk of Recoverability of Total Compensation Costs

The Company manages all of its total compensation costs, including pension and other post-employment and post-retirement benefits, subject to restrictions and requirements imposed by the collective bargaining process. Should any element of total compensation costs be disallowed in whole or part by the OEB and not be recoverable from customers in rates, the costs could be material and could decrease net income, which could have a material adverse effect on the Company.

Other Post-Employment and Post-Retirement Benefits Risks

The Company provides other post-employment and post-retirement benefits, including workers compensation benefits and long-term disability benefits to qualifying employees. The OEB has begun a consultation process that will examine pensions and other post-employment benefits in regulated utilities. The objectives of the consultation are to develop standard principles to guide the OEB's review of pension and other post-employment and post-retirement benefits costs in the future, to establish specific information requirements for application and to establish appropriate regulatory mechanisms for cost recovery which can be applied consistently across the gas and electricity sectors for rate-regulated utilities. The outcome of this consultation process is uncertain and the Company is unable to assess the impact of the potential changes stemming from the review at this time. A determination that some of the Company's post-employment and post-retirement benefit costs are not recoverable could have a material adverse effect on the Company.

Risk Associated with Outsourcing Arrangements

Consistent with Hydro One's strategy of reducing operating costs, it has entered into an outsourcing arrangement with a third party for the provision of back office services and call centre services. If the outsourcing arrangement or statements of work thereunder are terminated for any reason or expire before a new supplier is selected and fully transitioned, the Company could be required to incur significant expenses to transfer to another service provider or insource, which could have a material adverse effect on the Company's business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

The Province owns some of the corridor lands underlying the Company's transmission system. Although the Company has the statutory right to use these transmission corridors, the Company may be limited in its options to expand or operate its systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of the Company's systems may increase safety or environmental risks, which could have a material adverse effect on the Company.

Litigation Risks

In the normal course of the Company's operations, it becomes involved in, is named as a party to and is the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company’s business operations, which could adversely affect the Company. See also “Other Developments – Class Action Lawsuit”.

Transmission Assets on Third-Party Lands Risk

Some of the lands on which the Company’s transmission assets are located are owned by third parties, including the Province and federal Crown, and are or may become subject to land claims by First Nations. The Company requires valid occupation rights to occupy such lands (which may take the form of land use permits, easements or otherwise). If the Company does not have valid occupational rights on third-party owned lands or has occupational rights that are subject to expiry, it may incur material costs to obtain or renew such occupational rights, or if such occupational rights cannot be renewed or obtained it may incur material costs to remove and relocate its assets and restore the subject land. If the Company does not have valid occupational rights and must incur costs as a result, this could have a material adverse effect on the Company or otherwise materially adversely impact the Company’s operations.

Reputational and Public Opinion Risk

Reputation risk is the risk of a negative impact to the Company’s business, operations or financial condition that could result from a deterioration of Hydro One’s reputation. The Company’s reputation could be negatively impacted by changes in public opinion, attitudes towards the Company’s privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events could have negative impacts on the Company’s business and prospects including, but not limited to, delays or denials of requisite approvals and accommodations for the Company’s planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

Risks Relating to the Company’s Relationship with the Province

Ownership and Continued Influence by the Province and Voting Power; Share Ownership Restrictions

The Province currently owns approximately 70.1% of the outstanding common shares of Hydro One. The *Electricity Act* restricts the Province from selling voting securities of Hydro One (including common shares) of any class or series if it would own less than 40% of the outstanding number of voting securities of that class or series after the sale and in certain circumstances also requires the Province to take steps to maintain that level of ownership. Accordingly, the Province is expected to continue to maintain a significant ownership interest in voting securities of Hydro One for an indefinite period.

As a result of its significant ownership of the common shares of Hydro One, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes, subject to the restrictions in the governance agreement entered into between Hydro One and the Province dated November 5, 2015 (Governance Agreement; available on SEDAR at www.sedar.com). Despite the terms of the Governance Agreement in which the Province has agreed to engage in the business and affairs of the Company as an investor and not as a manager, there is a risk that the Province’s engagement in the business and affairs of the Company as an investor will be informed by its policy objectives and may influence the conduct of the business and affairs of the Company in ways that may not be aligned with the interests of other shareholders.

The share ownership restrictions in the *Electricity Act* (Share Ownership Restrictions) and the Province’s significant ownership of common shares of Hydro One together effectively prohibit one or more persons acting together from acquiring control of Hydro One. They also may limit or discourage transactions involving other fundamental changes to Hydro One and the ability of other shareholders to successfully contest the election of the directors proposed for election pursuant to the Governance Agreement. The Share Ownership Restrictions may also discourage trading in, and may limit the market for, the common shares and other voting securities.

Nomination of Directors and Confirmation of Chief Executive Officer and Chair

Although director nominees are required to be independent of both the Company and the Province pursuant to the Governance Agreement, there is a risk that the Province will nominate or confirm individuals who satisfy the independence requirements but who it considers are disposed to support and advance its policy objectives and give disproportionate weight to the Province’s interests in exercising their business judgment and balancing the interests of the stakeholders of Hydro One. This, combined with the fact certain matters require a two-thirds vote of the Board of Directors, could allow the Province to unduly influence certain Board actions such as confirmation of the Chair and confirmation of the Chief Executive Officer.

Board Removal Rights

Under the Governance Agreement, the Province has the right to withhold from voting in favour of all director nominees and has the right to seek to remove and replace the entire Board of Directors, including in each case its own director nominees but excluding the Chief Executive Officer and, at the Province's discretion, the Chair. In exercising these rights in any particular circumstance, the Province is entitled to vote in its sole interest, which may not be aligned with the interests of other shareholders.

More Extensive Regulation

Although under the Governance Agreement, the Province has agreed to engage in the business and affairs of Hydro One as an investor and not as a manager and has stated that its intention is to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario, there is a risk that the Province will exercise its legislative and regulatory power to achieve policy objectives in a manner that has a material adverse effect on the Company.

Prohibitions on Selling the Company's Transmission or Distribution Business

The *Electricity Act* prohibits the Company from selling all or substantially all of the business, property or assets related to its transmission system or distribution system that is regulated by the OEB. There is a risk that these prohibitions may limit the ability of the Company to engage in sale transactions involving a substantial portion of either system, even where such a transaction may otherwise be considered to provide substantial benefits to the Company and the holders of the common shares.

Future Sales of Common Shares by the Province

The Province has indicated that it currently intends to sell further common shares of Hydro One over time, until it holds approximately 40% of the common shares, subject to the selling restrictions agreed with the Underwriters. The registration rights agreement between Hydro One and the Province dated November 5, 2015 (available on SEDAR at www.sedar.com) also grants the Province the right to request that Hydro One file one or more prospectuses and take other procedural steps to facilitate secondary offerings by the Province of the common shares of Hydro One. Future sales of common shares of Hydro One by the Province, or the perception that such sales could occur, may materially adversely affect market prices for these common shares and impede Hydro One's ability to raise capital through the issuance of additional common shares, including the number of common shares that Hydro One may be able to sell at a particular time or the total proceeds that may be realized.

Limitations on Enforcing the Governance Agreement

The Governance Agreement includes commitments by the Province restricting the exercise of its rights as a holder of voting securities, including with respect to the maximum number of directors that the Province may nominate and on how the Province will vote with respect to other director nominees. Hydro One's ability to obtain an effective remedy against the Province, if the Province were not to comply with these commitments, is limited as a result of the *Proceedings Against the Crown Act* (Ontario). This legislation provides that the remedies of injunction and specific performance are not available against the Province, although a court may make an order declaratory of the rights of the parties, which may influence the Province's actions. A remedy of damages would be available to Hydro One, but damages may not be an effective remedy, depending on the nature of the Province's non-compliance with the Governance Agreement.

Critical Accounting Estimates and Judgments

The preparation of Hydro One Consolidated Financial Statements requires the Company to make key estimates and critical judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. Hydro One bases its estimates and judgments on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities, as well as identifying and assessing the Company's accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. Hydro One has identified the following critical accounting estimates used in the preparation of its Consolidated Financial Statements:

Revenues

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Accounts Receivable and Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs.

Regulatory Assets and Liabilities

Hydro One's regulatory assets represent certain amounts receivable from future electricity customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, share-based compensation costs, and environmental liabilities. The Company's regulatory liabilities represent certain amounts that are refundable to future electricity customers, and pertain primarily to OEB deferral and variance accounts. The regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the amounts have been approved for inclusion in the electricity rates by the OEB, or if such approval is judged to be probable by management. If management judges that it is no longer probable that the OEB will allow the inclusion of a regulatory asset or liability in future electricity rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgment is made by management.

Environmental Liabilities

Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment, and for the assessment and remediation of chemically contaminated lands. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

Hydro One's employee future benefits consist of pension and post-retirement and post-employment plans, and include pension, group life insurance, health care, and long-term disability benefits provided to the Company's current and retired employees. Employee future benefits costs are included in Hydro One's labour costs that are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets. Changes in assumptions affect the benefit obligation of the employee future benefits and the amounts that will be charged to results of operations or capitalized in future years. The following significant assumptions and estimates are used to determine employee future benefit costs and obligations:

Weighted Average Discount Rate

The weighted average discount rate used to calculate the employee future benefits obligation is determined at each year end by referring to the most recently available market interest rates based on "AA"-rated corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rate at December 31, 2016 decreased to 3.90% (from 4.00% at December 31, 2015) for pension benefits and decreased to 3.90% (from 4.10% used at December 31, 2015) for the post-retirement and post-employment plans. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities for the pension, post-retirement and post-employment plans for accounting purposes. The liabilities are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

Expected Rate of Return on Plan Assets

The expected rate of return on pension plan assets is based on expectations of long-term rates of return at the beginning of the year and reflects a pension asset mix consistent with the pension plan's current investment policy.

Rates of return on the respective portfolios are determined with reference to respective published market indices. The expected rate of return on pension plan assets reflects the Company's long-term expectations. The Company believes that this assumption is reasonable because, with the pension plan's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a lower return than might be expected by investing in equities alone. In the short term, the pension plan can experience fluctuations in actual rates of return.

Rate of Cost of Living Increase

The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which increased from 1.50% per annum as at December 31, 2015 to approximately 1.80% per annum as at December 31, 2016. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for employee future benefits liability valuation purposes as at December 31, 2016.

Mortality Assumptions

The Company's employee future benefits liability is also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in the employee future benefits liability. The mortality assumption used at December 31, 2016 is 95% of 2014 Canadian Pensioners Mortality Private Sector table projected generationally using improvement Scale B (compared to 100% of 2014 Canadian Pensioners Mortality Public Sector table projected generationally using improvement Scale B used at December 31, 2015). The mortality table was updated based on a review of the historical mortality experience of the pension plan members.

Rate of Increase in Health Care Cost Trends

The costs of post-retirement and post-employment benefits are determined at the beginning of the year and are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in a $23 million increase in 2016 interest cost plus service cost, and a $289 million increase in the benefit liability at December 31, 2016.

Business Combinations

Management's judgment is required to estimate the purchase price, to identify and to determine fair value of all assets and liabilities acquired. The determination of the fair value of assets and liabilities acquired is based upon management's estimates and certain assumptions.

Taxes

Hydro One assesses the likelihood that deferred tax assets will be recovered from future taxable income. To the extent management considers it is more likely than not that some portion or all of the deferred tax assets will not be realized, a valuation allowance is recognized.

Asset Impairment

Within Hydro One's regulated businesses, the carrying costs of most of the long-lived assets are included in the rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through OEB-approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. The Company regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2016, no asset impairment had been recorded for assets within Hydro One's regulated or unregulated businesses.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Hydro One has concluded that goodwill was not impaired at December 31, 2016. Goodwill represents the cost of acquired distribution and transmission companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date.

Disclosure Controls And Internal Controls Over Financial Reporting

Internal controls have been documented and tested for adequacy and effectiveness, and continue to be refined over all business processes.

In compliance with the requirements of National Instrument 52-109, the Company's Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2016, together with other financial information included in the Company's securities filings. The Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to the Company is made known within the Company. Further, the Certifying Officers have certified that internal controls over financial reporting (ICFR) have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Consolidated Financial Statements. Based on the evaluation of the design and operating effectiveness of the Company's DC&P and ICFR, the Certifying Officers concluded that the Company's DC&P and ICFR were effective as at December 31, 2016.

New Accounting Pronouncements

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One.

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Impact on Hydro One
2014-16	November 2014	This update clarifies that all relevant terms and features should be considered in evaluating the nature of a host contract for hybrid financial instruments issued in the form of a share. The nature of the host contract depends upon the economic characteristics and risks of the entire hybrid financial instrument.	January 1, 2016	No material impact upon adoption
2015-01	January 2015	Extraordinary items are no longer required to be presented separately in the income statement.	January 1, 2016	No material impact upon adoption
2015-02	February 2015	Guidance on analysis to be performed to determine whether certain types of legal entities should be consolidated.	January 1, 2016	No material impact upon adoption
2015-03	April 2015	Debt issuance costs are required to be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability consistent with debt discounts or premiums.	January 1, 2016	Reclassification of deferred debt issuance costs and net unamortized debt premiums as an offset to long-term debt. Applied retrospectively.
2015-05	April 2015	Cloud computing arrangements that have been assessed to contain a software licence should be accounted for as internal-use software.	January 1, 2016	No material impact upon adoption
2015-16	September 2015	Adjustments to provisional amounts that are identified during the measurement period of a business combination in the reporting period in which the adjustment amount is determined are required to be recognized. The amount recorded in current period earnings are required to be presented separately on the face of the income statement or disclosed in the notes by line item.	January 1, 2016	No material impact upon adoption
2015-17	November 2015	All deferred tax assets and liabilities are required to be classified as noncurrent on the balance sheet.	January 1, 2017	This ASU was early adopted as of April 1, 2016 and was applied prospectively. As a result, the current portions of the Company's deferred income tax assets are reclassified as noncurrent assets on the consolidated Balance Sheet. Prior periods were not retrospectively adjusted.
2016-09	March 2016	Several aspects of the accounting for share-based payment transactions were simplified, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows.	January 1, 2017	This ASU was early adopted as of October 1, 2016 and was applied retrospectively. As a result, the Company accounts for forfeitures as they occur. There were no other material impacts upon adoption.

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20	May 2014 – December 2016	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed its initial assessment and has identified relevant revenue streams. No quantitative determination has been made as a detailed assessment is now underway and will continue through to the third quarter of 2017, with the end result being a determination of the financial impact of this standard. The Company is on track for implementation of this standard by the effective date.
2016-01	January 2016	This update requires equity investments to be measured at fair value with changes in fair value recognized in net income, and requires enhanced disclosures and presentation of financial assets and liabilities in the financial statements. This ASU also simplifies the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment.	January 1, 2018	Under assessment
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of all existing leases, which will be followed by a detailed review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-05	March 2016	The amendments clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under Topic 815 does not, in and of itself, require de-designation of that hedging relationship provided that all other hedge accounting criteria continue to be met.	January 1, 2018	Under assessment
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No material impact
2016-07	March 2016	The requirement to retroactively adopt the equity method of accounting if an investment qualifies for use of the equity method as a result of an increase in the level of ownership or degree of influence has been eliminated.	January 1, 2017	No material impact
2016-11	May 2016	This amendment covers the SEC Staff's rescinding of certain SEC Staff observer comments that are codified in Topic 605 and Topic 932, effective upon the adoption of Topic 606 and Topic 815, effective to coincide with the effective date of Update 2014-16.	January 1, 2019	No material impact

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-13	June 2016	The amendment provides users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date.	January 1, 2019	Under assessment
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	Under assessment
2016-16	October 2016	The amendment eliminates the prohibition of recognizing current and deferred income taxes for an intra-entity asset transfer, other than inventory, until the asset has been sold to an outside party. The amendment will permit income tax consequences of such transfers to be recognized when the transfer occurs.	January 1, 2018	Under assessment
2016-18	November 2016	The amendment requires that restricted cash or restricted cash equivalents be included with cash and cash equivalents when reconciling the beginning and end-of-period balances in the statement of cash flows.	January 1, 2018	Under assessment
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	Under assessment

Summary of Fourth Quarter Results of Operations

Three months ended December 31 *(millions of dollars, except EPS)*	2016	2015	Change
Revenues			
Distribution	1,228	1,148	7.0%
Transmission	373	361	3.3%
Other	13	13	–
	1,614	1,522	6.0%
Costs			
Purchased power	858	786	9.2%
OM&A			
Distribution	163	146	11.6%
Transmission	98	126	(22.2%)
Other	26	29	(10.3%)
	287	301	(4.7%)
Depreciation and amortization	204	193	5.7%
	1,349	1,280	5.4%
Income before financing charges and income taxes	265	242	9.5%
Financing charges	101	94	7.4%
Income before income taxes	164	148	10.8%
Income tax expense	29	1	100.0%
Net income	135	147	(8.2%)
Net income attributable to common shareholders of Hydro One	128	143	(10.5%)
Basic EPS	$ 0.22	$ 0.26	(15.4%)
Diluted EPS	$ 0.21	$ 0.26	(19.2%)
Capital investments			
Distribution	201	198	1.5%
Transmission	274	251	9.2%
Other	2	2	–
	477	451	5.8%

Net Income

Net income attributable to common shareholders for the quarter ended December 31, 2016 of $128 million is a decrease of $15 million or 10.5% from the prior year. Excluding the effect of an IPO-related positive tax adjustment of $19 million in the fourth quarter of 2015, net income for the quarter increased by 3.2%.

Revenues

The quarterly increase of $12 million or 3.3% in transmission revenues was primarily due to higher average monthly Ontario 60-minute peak demand as several extremely cold days during the quarter increased peak transmission demand and OEB-approved transmission rate increases.

The quarterly increase of $80 million or 7.0% in distribution revenues was primarily due to higher power costs from generators that are passed on to customers and increased OEB-approved distribution rates for 2016, partially offset by lower energy consumption resulting from milder weather.

OM&A Costs

The quarterly decrease of $28 million or 22.2% in transmission OM&A costs was primarily due to lower project cost and inventory write-downs and lower expenditures related to forestry control and line clearing on the Company's transmission rights-of-way.

The quarterly increase of $17 million or 11.6% in distribution OM&A costs was primarily due to higher volume of vegetation management activities, partially offset by lower costs related to restoring power services and storm response.

Depreciation and Amortization

The increase of $11 million or 5.7% in depreciation and amortization costs for the fourth quarter of 2016 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Financing Charges

The quarterly increase of $7 million or 7.4% in financing charges was primarily due to an increase in interest expense on long-term debt resulting from the increase in weighted average long-term debt outstanding during the quarter.

Income Tax Expense

Income tax expense for the fourth quarter of 2016 increased by $28 million compared to 2015, and the Company realized an effective tax rate of approximately 17.7% in the fourth quarter of 2016 compared to approximately 0.7% in 2015. The increase in tax expense is primarily due to the following:

- the effect of an IPO-related positive tax adjustment of $19 million in the fourth quarter of 2015;
- higher income before taxes in the fourth quarter of 2016; and
- a decrease in deductible temporary differences such as capitalized pension deducted for tax purposes.

Capital Investments

The increase in transmission capital investments during the fourth quarter was primarily due to

- an increased volume of work on insulator replacements;
- an increased volume of integrated station component replacements to replace deteriorated assets at transmission stations; and
- higher volume of demand work associated with equipment failures and spare transformer equipment purchases; partially offset by
- reduced work on the Clarington Transmission Station as the project nears completion.

The increase in distribution capital investments during the fourth quarter was primarily due to

- increased investments related to information technology infrastructure and customer programs together with upgrade and enhancement projects, including investments to integrate mobile technology with the Company's existing work management tools;
- higher volume of facility upgrades and construction of new operation centres; and
- higher volumes of work associated with further enabling certain of Hydro One's assets to be jointly used by the telecommunications and cable television industries, as well as relocation of poles, conductors and other equipment as required by municipal and provincial road authorities; partially offset by
- higher storm restoration work in the prior year primarily as a result of two significant wind storms during the fourth quarter of 2015.

Forward-looking Statements And Information

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to: statements regarding the Company's transmission and distribution rates resulting from rate applications; statements regarding the Company's liquidity and capital resources and operational requirements; statements about the standby credit facilities; expectations regarding the Company's financing activities; statements regarding the Company's maturing debt; statements related to credit ratings; statements regarding ongoing and planned projects and/or initiatives, including expected results and completion dates; statements regarding expected future capital and development investments, the timing of these expenditures and the Company's investment plans; statements regarding contractual obligations and other commercial commitments; statements related to the OEB; statements regarding future pension contributions, the pension plan and valuations; expectations related to work force demographics; statements about collective agreements; statements related to dividends; statements related to claims; expectations regarding taxes; statements related to occupational rights; statements about non-GAAP measures; statements related to critical accounting estimates, including expectations regarding employee future benefits, environmental liabilities, and regulatory assets and liabilities; expectations related to the effect of interest rates; statements about the Company's reputation; statements regarding cyber and data security; statements related to future sales of shares of Hydro One; statements related to the Company's relationship with the Province; statements regarding recent accounting-related guidance; expectations related to tax impacts; statements related to the Universal Base Shelf Prospectus; and statements related to the Company's acquisitions, including statements about Great Lakes Power and Orillia Power. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third-party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on Reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security and maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section "Risk Management and Risk Factors" in this MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com and the Company's website at www.HydroOne.com/Investors.

Management's Report

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Limited (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 9, 2017.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition, management has assessed the design and operating effectiveness of the Company's internal control over financial reporting in accordance with the criteria set forth in Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2016. The effectiveness of these internal controls is reported to the Audit Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been audited by KPMG LLP, independent external auditors appointed by the shareholders of the Company. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit Committee, with and without the presence of management, to discuss their audit findings.

The President and Chief Executive Officer and the Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting.

On behalf of Hydro One's management:

Mayo Schmidt President and Chief Executive Officer	Michael Vels Chief Financial Officer

Independent Auditors' Report

To the Shareholders of Hydro One Limited

We have audited the accompanying Consolidated Financial Statements of Hydro One Limited, which comprise the consolidated balance sheets as at December 31, 2016 and December 31, 2015, the consolidated statements of operations and comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of Consolidated Financial Statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Consolidated Financial Statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the Consolidated Financial Statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the Consolidated Financial Statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the Consolidated Financial Statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the consolidated financial position of Hydro One Limited as at December 31, 2016 and December 31, 2015, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
February 9, 2017

Consolidated Statements of Operations and Comprehensive Income

For the years ended December 31, 2016 and 2015

Year ended December 31 (millions of Canadian dollars, except per share amounts)	2016	2015
Revenues		
Distribution (includes $160 related party revenues; 2015 – $159) *(Note 26)*	4,915	4,949
Transmission (includes $1,553 related party revenues; 2015 – $1,554) *(Note 26)*	1,584	1,536
Other	53	53
	6,552	6,538
Costs		
Purchased power (includes $2,103 related party costs; 2015 – $2,335) *(Note 26)*	3,427	3,450
Operation, maintenance and administration *(Note 26)*	1,069	1,135
Depreciation and amortization *(Note 5)*	778	759
	5,274	5,344
Income before financing charges and income taxes	1,278	1,194
Financing charges *(Note 6)*	393	376
Income before income taxes	885	818
Income taxes *(Notes 7, 26)*	139	105
Net income	746	713
Other comprehensive income	–	1
Comprehensive income	746	714
Net income attributable to:		
Noncontrolling interest *(Note 25)*	6	10
Preferred shareholders	19	13
Common shareholders	721	690
	746	713
Comprehensive income attributable to:		
Noncontrolling interest *(Note 25)*	6	10
Preferred shareholders	19	13
Common shareholders	721	691
	746	714
Earnings per common share *(Note 23)*		
Basic	$ 1.21	$ 1.39
Diluted	$ 1.21	$ 1.39
Dividends per common share declared *(Note 22)*	$ 0.97	$ 1.83

See accompanying notes to Consolidated Financial Statements.

2
CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

At December 31, 2016 and 2015

December 31 (millions of Canadian dollars)	2016	2015
Assets		
Current assets:		
Cash and cash equivalents	50	94
Accounts receivable *(Note 8)*	838	776
Due from related parties *(Note 26)*	158	191
Other current assets *(Note 9)*	102	105
	1,148	1,166
Property, plant and equipment *(Note 10)*	19,140	17,968
Other long-term assets:		
Regulatory assets *(Note 12)*	3,145	3,015
Deferred income tax assets *(Note 7)*	1,235	1,636
Intangible assets *(Note 11)*	349	336
Goodwill *(Note 4)*	327	163
Other assets	7	10
	5,063	5,160
Total assets	25,351	24,294
Liabilities		
Current liabilities:		
Short-term notes payable *(Note 15)*	469	1,491
Long-term debt payable within one year *(Note 15)*	602	500
Accounts payable and other current liabilities *(Note 13)*	945	868
Due to related parties *(Note 26)*	147	138
	2,163	2,997
Long-term liabilities:		
Long-term debt (includes $548 measured at fair value; 2015 – $51) *(Notes 15, 16)*	10,078	8,207
Regulatory liabilities *(Note 12)*	209	236
Deferred income tax liabilities *(Note 7)*	60	207
Other long-term liabilities *(Note 14)*	2,752	2,723
	13,099	11,373
Total liabilities	15,262	14,370
Contingencies and Commitments (Notes 28, 29)		
Subsequent Events (Note 31)		
Noncontrolling interest subject to redemption *(Note 25)*	22	23
Equity		
Common shares *(Notes 21, 22)*	5,623	5,623
Preferred shares *(Notes 21, 22)*	418	418
Additional paid-in capital *(Note 24)*	34	10
Retained earnings	3,950	3,806
Accumulated other comprehensive loss	(8)	(8)
Hydro One shareholders' equity	10,017	9,849
Noncontrolling interest *(Note 25)*	50	52
Total equity	10,067	9,901
	25,351	24,294

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

David Denison
Chair

Philip Orsino
Chair, Audit Committee

Consolidated Statements of Changes in Equity

For the years ended December 31, 2016 and 2015

Year ended December 31, 2016 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholders' Equity	Non-controlling Interest *(Note 25)*	Total Equity
January 1, 2016	5,623	418	10	3,806	(8)	9,849	52	9,901
Net income	–	–	–	740	–	740	4	744
Other comprehensive income	–	–	–	–	–	–	–	–
Distributions to noncontrolling interest	–	–	–	–	–	–	(6)	(6)
Dividends on preferred shares	–	–	–	(19)	–	(19)	–	(19)
Dividends on common shares	–	–	–	(577)	–	(577)	–	(577)
Stock-based compensation *(Note 24)*	–	–	24	–	–	24	–	24
December 31, 2016	5,623	418	34	3,950	(8)	10,017	50	10,067

Year ended December 31, 2015 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholders' Equity	Non-controlling Interest *(Note 25)*	Total Equity
January 1, 2015	3,314	–	–	4,249	(9)	7,554	49	7,603
Net income	–	–	–	703	–	703	7	710
Other comprehensive income	–	–	–	–	1	1	–	1
Distributions to noncontrolling interest	–	–	–	–	–	–	(4)	(4)
Dividends on preferred shares	–	–	–	(13)	–	(13)	–	(13)
Dividends on common shares	–	–	–	(875)	–	(875)	–	(875)
Hydro One Brampton spin-off *(Note 4)*	(196)	–	–	(258)	–	(454)	–	(454)
Pre-IPO Transactions *(Note 21)*	2,505	418	–	–	–	2,923	–	2,923
Stock-based compensation *(Note 24)*	–	–	10	–	–	10	–	10
December 31, 2015	5,623	418	10	3,806	(8)	9,849	52	9,901

See accompanying notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the years ended December 31, 2016 and 2015

Year ended December 31 (millions of Canadian dollars)	2016	2015
Operating activities		
Net income	746	713
Environmental expenditures	(20)	(19)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	688	668
Regulatory assets and liabilities	(16)	(3)
Deferred income taxes *(Note 7)*	114	(2,844)
Other	10	24
Changes in non-cash balances related to operations *(Note 27)*	134	213
Net cash from (used in) operating activities	1,656	(1,248)
Financing activities		
Long-term debt issued	2,300	350
Long-term debt repaid	(502)	(585)
Short-term notes issued	3,031	2,891
Short-term notes repaid	(4,053)	(1,400)
Common shares issued	–	2,600
Dividends paid	(596)	(888)
Distributions paid to noncontrolling interest	(9)	(5)
Change in bank indebtedness	–	(2)
Other	(10)	(7)
Net cash from financing activities	161	2,954
Investing activities		
Capital expenditures *(Note 27)*		
Property, plant and equipment	(1,600)	(1,595)
Intangible assets	(61)	(37)
Capital contributions received *(Note 27)*	21	57
Acquisitions *(Note 4)*	(224)	(90)
Investment in Hydro One Brampton *(Note 4)*	–	(53)
Other	3	6
Net cash used in investing activities	(1,861)	(1,712)
Net change in cash and cash equivalents	(44)	(6)
Cash and cash equivalents, beginning of year	94	100
Cash and cash equivalents, end of year	50	94

See accompanying notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

For the years ended December 31, 2016 and 2015

1. Description of The Business

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). On October 31, 2015, the Company acquired Hydro One Inc., a company previously wholly owned by the Province of Ontario (Province). The acquisition of Hydro One Inc. by Hydro One was accounted for as a common control transaction and Hydro One is a continuation of business operations of Hydro One Inc. At December 31, 2016, the Province holds approximately 70.1% (2015 – 84%) of the common shares of Hydro One. See note 21 for further details regarding the reorganization of Hydro One.

The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

2. Significant Accounting Policies

Basis of Consolidation and Preparation

These Consolidated Financial Statements include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

The comparative information to these Consolidated Financial Statements has been presented in a manner similar to the pooling-of-interests method. The comparative information consists of the results of operations of Hydro One Inc. prior to October 31, 2015, and the consolidated results of operations of Hydro One from the date of incorporation on August 31, 2015 to December 31, 2015, which include the results of Hydro One Inc. subsequent to its acquisition on October 31, 2015. The comparative information has been combined using historical amounts. In addition, Hydro One's issued and outstanding common shares prior to October 31, 2015 have been retroactively adjusted for the purposes of presentation to reflect the effects of the acquisition of Hydro One Inc. using the exchange ratio established for the acquisition. The Consolidated Financial Statements are referred to as "consolidated" for all periods presented.

On August 31, 2015, Hydro One Inc. completed the spin-off of its subsidiary, Hydro One Brampton Networks Inc. (Hydro One Brampton) to the Province (see note 4). The comparative information to these Consolidated Financial Statements includes the results of Hydro One Brampton up to August 31, 2015.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations, goodwill and asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Rate Setting

The Company's Transmission Business consists of the transmission business of Hydro One Inc., which includes the transmission business of Hydro One Networks Inc. (Hydro One Networks), Hydro One Sault Ste. Marie LP (previously Great Lakes Power Transmission LP (Great Lakes Power)), and its 66% interest in B2M Limited Partnership (B2M LP). The Company's Distribution Business consists of the distribution business of Hydro One Inc., which includes the distribution businesses of Hydro One Networks, as well as Hydro One Remote Communities Inc. (Hydro One Remote Communities).

Transmission

In November 2015, the OEB approved Hydro One Networks' 2016 transmission rates revenue requirement of $1,480 million.

In December 2015, the OEB approved B2M LP's 2015-2019 rates revenue requirements of $39 million, $36 million, $37 million, $38 million and $37 million for the respective years. On January 14, 2016, the OEB approved the B2M LP revenue requirement recovery through the 2016 Uniform Transmission Rates, and the establishment of a deferral account to capture costs of Tax Rate and Rule changes.

Distribution

In March 2015, the OEB approved Hydro One Networks' distribution revenue requirements of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The OEB has subsequently approved updated revenue requirements of $1,410 million for 2016 and $1,415 million for 2017.

On March 17, 2016, the OEB approved an increase of 2.10% to Hydro One Remote Communities' basic rates for the distribution and generation of electricity, with an effective date of May 1, 2016.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations in the period that the assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for rural, residential, and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to shareholders of Hydro One. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income and other comprehensive income attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Income Taxes

Prior to the IPO, Hydro One was exempt from tax under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (Federal Tax Regime). However, under the *Electricity Act*, Hydro One was required to make payments in lieu of tax (PILs) to the Ontario Electricity Financing Corporation (OEFC) (PILs Regime). The PILs were, in general, based on the amount of tax that Hydro One would otherwise be liable to pay under the Federal Tax Regime if it was not exempt from taxes under those statutes. In connection with the IPO of Hydro One, Hydro One's exemption from tax under the Federal Tax Regime ceased to apply. Upon exiting the PILs Regime, Hydro One is required to make corporate income tax payments to the Canada Revenue Agency (CRA) under the Federal Tax Regime.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the deferred income tax asset to report the net balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2015. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment:			
Transmission	56 years	1% – 3%	2%
Distribution	46 years	1% – 7%	2%
Communication	16 years	1% –15%	6%
Administration and service	18 years	1% –20%	7%
Intangible assets	10 years	10%	10%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

For the year ended December 31, 2016, based on the qualitative assessment performed as at September 30, 2016, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 2016.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2016 and 2015, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts net of related debt on the Consolidated Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 16 – Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized on its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2016 or 2015.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

Defined Benefit Pension

Defined benefit pension costs are recorded on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year. Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan.

Post-retirement and Post-employment Benefits

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. The actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Stock-Based Compensation

Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Forfeitures are recognized as they occur (see note 3).

Directors' Deferred Share Unit (DSU) Plan

The Company records the liabilities associated with its Directors' DSU Plan at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Company's common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures its LTIP at fair value based on the grant date share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with contaminated land assessment and remediation and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Company's asset retirement obligations recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of specific switching stations located on unowned sites.

3. New Accounting Pronouncements

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board (FASB) that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Impact on Hydro One
2014-16	November 2014	This update clarifies that all relevant terms and features should be considered in evaluating the nature of a host contract for hybrid financial instruments issued in the form of a share. The nature of the host contract depends upon the economic characteristics and risks of the entire hybrid financial instrument.	January 1, 2016	No material impact upon adoption
2015-01	January 2015	Extraordinary items are no longer required to be presented separately in the income statement.	January 1, 2016	No material impact upon adoption
2015-02	February 2015	Guidance on analysis to be performed to determine whether certain types of legal entities should be consolidated.	January 1, 2016	No material impact upon adoption
2015-03	April 2015	Debt issuance costs are required to be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability consistent with debt discounts or premiums.	January 1, 2016	Reclassification of deferred debt issuance costs and net unamortized debt premiums as an offset to long-term debt. Applied retrospectively (see note 15).
2015-05	April 2015	Cloud computing arrangements that have been assessed to contain a software licence should be accounted for as internal-use software.	January 1, 2016	No material impact upon adoption
2015-16	September 2015	Adjustments to provisional amounts that are identified during the measurement period of a business combination in the reporting period in which the adjustment amount is determined are required to be recognized. The amount recorded in current period earnings are required to be presented separately on the face of the income statement or disclosed in the notes by line item.	January 1, 2016	No material impact upon adoption
2015-17	November 2015	All deferred tax assets and liabilities are required to be classified as noncurrent on the balance sheet.	January 1, 2017	This ASU was early adopted as of April 1, 2016 and was applied prospectively. As a result, the current portions of the Company's deferred income tax assets are reclassified as noncurrent assets on the consolidated Balance Sheet. Prior periods were not retrospectively adjusted (see note 7).
2016-09	March 2016	Several aspects of the accounting for share-based payment transactions were simplified, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows.	January 1, 2017	This ASU was early adopted as of October 1, 2016 and was applied retrospectively. As a result, the Company accounts for forfeitures as they occur. There were no other material impacts upon adoption.

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20	May 2014 – December 2016	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed its initial assessment and has identified relevant revenue streams. No quantitative determination has been made as a detailed assessment is now underway and will continue through to the third quarter of 2017, with the end result being a determination of the financial impact of this standard. The Company is on track for implementation of this standard by the effective date.
2016-01	January 2016	This update requires equity investments to be measured at fair value with changes in fair value recognized in net income, and requires enhanced disclosures and presentation of financial assets and liabilities in the financial statements. This ASU also simplifies the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment.	January 1, 2018	Under assessment
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of all existing leases, which will be followed by a detailed review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-05	March 2016	The amendments clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under Topic 815 does not, in and of itself, require de-designation of that hedging relationship provided that all other hedge accounting criteria continue to be met.	January 1, 2018	Under assessment
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No material impact
2016-07	March 2016	The requirement to retroactively adopt the equity method of accounting if an investment qualifies for use of the equity method as a result of an increase in the level of ownership or degree of influence has been eliminated.	January 1, 2017	No material impact
2016-11	May 2016	This amendment covers the SEC Staff's rescinding of certain SEC Staff observer comments that are codified in Topic 605 and Topic 932, effective upon the adoption of Topic 606 and Topic 815, effective to coincide with the effective date of Update 2014-16.	January 1, 2019	No material impact

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-13	June 2016	The amendment provides users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date.	January 1, 2019	Under assessment
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	Under assessment
2016-16	October 2016	The amendment eliminates the prohibition of recognizing current and deferred income taxes for an intra-entity asset transfer, other than inventory, until the asset has been sold to an outside party. The amendment will permit income tax consequences of such transfers to be recognized when the transfer occurs.	January 1, 2018	Under assessment
2016-18	November 2016	The amendment requires that restricted cash or restricted cash equivalents be included with cash and cash equivalents when reconciling the beginning and end-of-period balances in the statement of cash flows.	January 1, 2018	Under assessment
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	Under assessment

4. Business Combinations

Acquisition of Great Lakes Power

On October 31, 2016, Hydro One acquired Great Lakes Power, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario from Brookfield Infrastructure Holdings Inc. The total purchase price for Great Lakes Power was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. The following table summarizes the determination of the final fair value of the assets acquired and liabilities assumed:

(millions of dollars)	
Cash and cash equivalents	5
Property, plant and equipment	221
Intangible assets	1
Regulatory assets	50
Goodwill	159
Working capital	(2)
Long-term debt	(186)
Pension and post-employment benefit liabilities, net	(5)
Deferred income taxes	(17)
	226

Goodwill of approximately $159 million arising from the Great Lakes Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Great Lakes Power. Great Lakes Power contributed revenues of

3 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

$6 million and less than $1 million of net income to the Company's consolidated financial results for the year ended December 31, 2016. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Great Lakes Power's financial information is not material to the Company's consolidated financial results for the year ended December 31, 2016 and therefore, has not been disclosed on a pro forma basis. On January 16, 2017, the name of Great Lakes Power was changed to Hydro One Sault Ste. Marie LP.

Agreement to Purchase Orillia Power

On August 15, 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power), an electricity distribution company located in Simcoe County, Ontario, from the City of Orillia for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments. The acquisition is subject to regulatory approval by the OEB.

Acquisition of Woodstock Hydro

On October 31, 2015, Hydro One acquired Woodstock Hydro Holdings Inc. (Woodstock Hydro), an electricity distribution company located in southwestern Ontario. The total purchase price for Woodstock Hydro was approximately $32 million. The purchase price was finalized and the Company made the final purchase price payment of $3 million in 2016. The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

(millions of dollars)	
Working capital	4
Property, plant and equipment	27
Intangible assets	1
Deferred income tax assets	2
Goodwill	22
Long-term debt	(17)
Derivative instruments	(3)
Post-retirement and post-employment benefit liability	(1)
Regulatory liabilities	(1)
Other long-term liabilities	(2)
	32

Goodwill of approximately $22 million arising from the Woodstock Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Woodstock Hydro. All of the goodwill was assigned to Hydro One's Distribution Business segment. Woodstock Hydro contributed revenues of $12 million and net income of $2 million to the Company's consolidated financial results for the year ended December 31, 2015. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Woodstock Hydro's financial information is not material to the Company's consolidated financial results for the year ended December 31, 2015 and therefore, has not been disclosed on a pro forma basis.

Acquisition of Haldimand Hydro

On June 30, 2015, Hydro One acquired Haldimand County Utilities Inc. (Haldimand Hydro), an electricity distribution company located in southwestern Ontario. The total purchase price for Haldimand Hydro was approximately $73 million. The purchase price was finalized in 2016. The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

(millions of dollars)	
Cash and cash equivalents	3
Working capital	5
Property, plant and equipment	52
Deferred income tax assets	1
Goodwill	33
Long-term debt	(18)
Regulatory liabilities	(3)
	73

Goodwill of approximately $33 million arising from the Haldimand Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Haldimand Hydro. All of the goodwill was assigned to Hydro One's Distribution Business segment. Haldimand Hydro contributed revenues of $32 million and net income of $6 million to the Company's consolidated financial results for the year ended December 31, 2015. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Haldimand Hydro's financial information is not material to the Company's consolidated financial results for the year ended December 31, 2015 and therefore, has not been disclosed on a pro forma basis.

Hydro One Brampton Spin-off

On August 31, 2015, Hydro One completed the spin-off of its subsidiary, Hydro One Brampton. The spin-off was accounted as a non-monetary, nonreciprocal transfer with the Province, based on its carrying values at August 31, 2015. Transactions that immediately preceded the spin-off as well as the spin-off were as follows:

- Hydro One subscribed for 357 common shares of Hydro One Brampton for an aggregate subscription price of $53 million; and
- Hydro One transferred to a company wholly owned by the Province all the issued and outstanding shares of Hydro One Brampton as a dividend-in-kind; and all of the long-term intercompany debt in aggregate principal amount of $193 million plus accrued interest of $3 million owed by Hydro One Brampton to Hydro One as a return of stated capital of $196 million on its common shares.

As a result of the spin-off, goodwill related to Hydro One Brampton of $60 million was eliminated from the Consolidated Balance Sheet.

5. Depreciation And Amortization

Year ended December 31 *(millions of dollars)*	**2016**	2015
Depreciation of property, plant and equipment	**612**	595
Asset removal costs	**90**	91
Amortization of intangible assets	**56**	54
Amortization of regulatory assets	**20**	19
	778	759

6. Financing Charges

Year ended December 31 *(millions of dollars)*	**2016**	2015
Interest on long-term debt	**424**	417
Interest on short-term notes	**9**	2
Other	**16**	14
Less: Interest capitalized on construction and development in progress	**(54)**	(52)
Interest earned on investments	**(2)**	(3)
Gain on interest-rate swap agreements	**–**	(2)
	393	376

7. Income Taxes

Income taxes / provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of dollars)*	2016	2015
Income taxes / provision for PILs at statutory rate	235	217
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(53)	(37)
Pension contributions in excess of pension expense	(16)	(25)
Overheads capitalized for accounting but deducted for tax purposes	(16)	(15)
Interest capitalized for accounting but deducted for tax purposes	(14)	(13)
Environmental expenditures	(5)	(5)
Other	5	(6)
Net temporary differences	(99)	(101)
Net tax benefit resulting from transition from PILs Regime to Federal Tax Regime	–	(19)
Hydro One Brampton spin-off	–	7
Net permanent differences	3	1
Total income taxes / provision for PILs	139	105

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2016	2015
Current income taxes / provision for PILs	25	2,949
Deferred income taxes / provision for (recovery of) PILs	114	(2,844)
Total income taxes / provision for PILs	139	105
Effective income tax rate	15.7%	12.8%

The provision for current income taxes / PILs is remitted to the CRA (Federal Tax Regime) and the OEFC (PILs Regime). At December 31, 2016, $14 million (2015 – $1 million) receivable from the CRA was included in other current assets and $6 million (2015 – $12 million) receivable from the OEFC was included in due from related parties on the Consolidated Balance Sheet.

In connection with the IPO in 2015, Hydro One's exemption from tax under the Federal Tax Regime ceased to apply. Under the PILs Regime, Hydro One was deemed to have disposed of its assets immediately before it lost its tax exempt status under the Federal Tax Regime, resulting in Hydro One making payments in lieu of tax (Departure Tax) totalling $2.6 billion. To enable Hydro One to make the Departure Tax payment, the Province subscribed for common shares of Hydro One for $2.6 billion in 2015 (see note 21). Hydro One used the proceeds of this share subscription to pay the Departure Tax.

The 2015 total income taxes / provision for PILs included a current provision of $2,600 million and a deferred recovery of $2,810 million resulting from the transition from the PILs Regime to the Federal Tax Regime. The deferred recovery was not included in the rate-setting process. Deferred income tax balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax basis of the Company's assets and liabilities. At December 31, 2016 and 2015, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of dollars)*	2016	2015
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	495	937
Non-depreciable capital property	271	271
Post-retirement and post-employment benefits expense in excess of cash payments	607	578
Environmental expenditures	74	75
Non-capital losses	213	62
Investment in subsidiaries	75	55
Other	30	10
	1,765	1,988
Less: valuation allowance	(352)	(333)
Total deferred income tax assets	1,413	1,655
Less: current portion	–	19
	1,413	1,636

December 31 *(millions of dollars)*	2016	2015
Deferred income tax liabilities		
Regulatory amounts that are not recognized for tax purposes	(153)	(153)
Goodwill	(10)	(10)
Capital cost allowance in excess of depreciation and amortization	(64)	(42)
Other	(11)	(2)
Total deferred income tax liabilities	(238)	(207)
Less: current portion	–	–
	(238)	(207)
Net deferred income tax assets	1,175	1,448

The net deferred income tax assets are presented on the Consolidated Balance Sheets as follows:

December 31 *(millions of dollars)*	2016	2015
Current:		
Other current assets	–	19
Long-term:		
Deferred income tax assets	1,235	1,636
Deferred income tax liabilities	(60)	(207)
Net deferred income tax assets	1,175	1,448

The valuation allowance for deferred tax assets as at December 31, 2016 was $352 million (2015 – $333 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets and investments in subsidiaries. As of December 31, 2016, the Company had non-capital losses carried forward available to reduce future years' taxable income, which expire as follows:

Year of expiry (millions of dollars)	**2016**	2015
2034	**2**	2
2035	**222**	232
2036	**580**	–
Total losses	**804**	234

8. Accounts Receivable

December 31 (millions of dollars)	**2016**	2015
Accounts receivable – billed	**431**	379
Accounts receivable – unbilled	**442**	458
Accounts receivable, gross	**873**	837
Allowance for doubtful accounts	**(35)**	(61)
Accounts receivable, net	**838**	776

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2016 and 2015:

Year ended December 31 (millions of dollars)	**2016**	2015
Allowance for doubtful accounts – January 1	**(61)**	(66)
Write-offs	**37**	37
Additions to allowance for doubtful accounts	**(11)**	(32)
Allowance for doubtful accounts – December 31	**(35)**	(61)

9. Other Current Assets

December 31 (millions of dollars)	**2016**	2015
Regulatory assets *(Note 12)*	**37**	36
Materials and supplies	**19**	21
Deferred income tax assets *(Notes 3, 7)*	**–**	19
Prepaid expenses and other assets	**46**	29
	102	105

10. Property, Plant And Equipment

December 31, 2016 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	14,692	4,862	910	10,740
Distribution	9,656	3,305	243	6,594
Communication	1,233	777	20	476
Administration and service	1,632	924	61	769
Easements	628	67	–	561
	27,841	9,935	1,234	19,140

December 31, 2015 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	13,704	4,621	853	9,936
Distribution	9,205	3,177	238	6,266
Communication	1,165	704	28	489
Administration and service	1,531	848	36	719
Easements	622	64	–	558
	26,227	9,414	1,155	17,968

Financing charges capitalized on property, plant and equipment under construction were $52 million in 2016 (2015 – $50 million).

11. Intangible Assets

December 31, 2016 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	621	326	53	348
Other	5	4	–	1
	626	330	53	349

December 31, 2015 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	579	270	24	333
Other	7	4	–	3
	586	274	24	336

Financing charges capitalized to intangible assets under development were $2 million in 2016 (2015 – $1 million). The estimated annual amortization expense for intangible assets is as follows: 2017 – $54 million; 2018 – $54 million; 2019 – $45 million; 2020 – $27 million; and 2021 – $26 million.

12. Regulatory Assets And Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 *(millions of dollars)*	2016	2015
Regulatory assets:		
Deferred income tax regulatory asset	1,587	1,445
Pension benefit regulatory asset	900	952
Post-retirement and post-employment benefits	243	240
Environmental	204	207
Retail settlement variance account	145	110
Debt premium	32	–
Share-based compensation	31	10
Distribution system code exemption	10	10
2015-2017 rate rider	7	20
B2M LP start-up costs	5	8
Pension cost variance	4	37
Other	14	12
Total regulatory assets	3,182	3,051
Less: current portion	37	36
	3,145	3,015
Regulatory liabilities:		
Green Energy expenditure variance	69	76
External revenue variance	64	87
CDM deferral variance	54	53
Deferred income tax regulatory liability	4	23
Other	18	16
Total regulatory liabilities	209	255
Less: current portion	–	19
	209	236

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2016 income tax expense would have been higher by approximately $104 million (2015 – $101 million).

Pension Benefit Regulatory Asset

In accordance with OEB rate orders, pension costs are recovered on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2016 OCI would have been higher by $52 million (2015 – $284 million).

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the re-measurement adjustment. In the absence of rate-regulated accounting, 2016 OCI would have been lower by $3 million (2015 – higher by $33 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2016, the environmental regulatory asset decreased by $1 million (2015 – $24 million) to reflect related changes in the Company's PCB liability, and increased by $10 million (2015 – $1 million) due to changes in the land assessment and remediation liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2016 operation, maintenance and administration expenses would have been higher by $9 million (2015 – lower by $23 million). In addition, 2016 amortization expense would have been lower by $20 million (2015 – $19 million), and 2016 financing charges would have been higher by $8 million (2015 – $10 million).

Retail Settlement Variance Account (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In March 2015, the OEB approved the disposition of the total RSVA balance accumulated from January 2012 to December 2013, including accrued interest, to be recovered through the 2015-2017 Rate Rider.

Debt Premium

The value of debt assumed in the acquisition of Great Lakes Power has been recorded at fair value in accordance with US GAAP – Business Combinations. The OEB allows for recovery of interest at the coupon rate of the Senior Secured Bonds and a regulatory asset has been recorded for the difference between the fair value and face value of this debt. The debt premium is recovered over the remaining term of the debt (see note 15).

Share-based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2016 operation, maintenance and administration expenses would have been higher by $9 million (2015 – $5 million).

Distribution System Code (DSC) Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the DSC, with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that identified specific expenditures can be recorded in a deferral account subject to the OEB's review in subsequent Hydro One Network distribution applications. In March 2015, the OEB approved the disposition of the DSC exemption deferral account at December 31, 2013, including accrued interest, which is being recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2015 or 2016.

2015-2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' distribution rate application for 2015-2019, the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015-2017 Rate Rider account includes the balances approved for disposition by the OEB and is being disposed in accordance with the OEB decision over a 32-month period ending on December 31, 2017.

B2M LP Start-up Costs

In December 2015, OEB issued its decision on B2M LP's application for 2015-2019 and as part of the decision approved the recovery of $8 million of start-up costs relating to B2M LP. The costs are being recovered over a four-year period which began in 2016, in accordance with the OEB decision.

Pension Cost Variance

A pension cost variance account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the excess of pension costs paid as compared to OEB-approved amounts. In March 2015, the OEB approved the disposition of the distribution business portion of the total pension cost variance account at December 31, 2013, including accrued interest, which is being recovered through the 2015-2017 Rate Rider. In the absence of rate-regulated accounting, 2016 revenue would have been higher by $25 million (2015 – lower by $6 million).

Green Energy Expenditure Variance

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account relates to the actual 2013 and 2014 CDM compared to the amounts included in 2013 and 2014 revenue requirements, respectively. There were no additions to this regulatory account in 2016.

13. Accounts Payable and Other Current Liabilities

December 31 *(millions of dollars)*	**2016**	2015
Accounts payable	**181**	155
Accrued liabilities	**659**	598
Accrued interest	**105**	96
Regulatory liabilities *(Note 12)*	**–**	19
	945	868

14. Other Long-Term Liabilities

December 31 *(millions of dollars)*	**2016**	2015
Post-retirement and post-employment benefit liability *(Note 18)*	**1,641**	1,560
Pension benefit liability *(Note 18)*	**900**	952
Environmental liabilities *(Note 19)*	**177**	185
Asset retirement obligations *(Note 20)*	**9**	9
Long-term accounts payable and other liabilities	**25**	17
	2,752	2,723

15. Debt and Credit Agreements

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion.

On August 15, 2016, Hydro One Inc. terminated its $1.5 billion revolving standby credit facility maturing in June 2020 and its $800 million three-year senior, revolving term credit facility maturing in October 2018 (collectively Prior Credit Facilities). On the same date, Hydro One Inc. entered into a new credit agreement for a $2.3 billion revolving credit facility maturing in June 2021 (New Credit Facility). The New Credit Facility ranks equally with any existing and future senior debt of Hydro One Inc., and has customary covenants substantially similar to the covenants under the Prior Credit Facilities. In addition, on November 7, 2016, the maturity date of Hydro One's $250 million credit facility was extended from November 2020 to November 2021.

At December 31, 2016, Hydro One's consolidated committed, unsecured and undrawn credit facilities totalling $2,550 million consisted of the following:

(millions of dollars)	Maturity	Amount
Hydro One Inc.		
Revolving standby credit facility	June 2021	2,300
Hydro One		
Five-year senior, revolving term credit facility	November 2021	250
Total		2,550

The Company may use the credit facilities for working capital and general corporate purposes. If used, interest on the credit facilities would apply based on Canadian benchmark rates. The obligation of each lender to make any credit extension under its credit facility is subject to various conditions including that no event of default has occurred or would result from such credit extension.

Long-Term Debt

At December 31, 2016, $10,523 million long-term debt was issued by Hydro One Inc. under Hydro One Inc.'s Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At December 31, 2016, $1.2 billion remained available for issuance until January 2018. In addition, at December 31, 2016, the Company had long-term debt of $184 million assumed as part of the Great Lakes Power acquisition.

The following table presents outstanding long-term debt at December 31, 2016 and 2015:

December 31 *(millions of dollars)*	2016	2015
4.64% Series 10 notes due 2016	–	450
Floating-rate Series 27 notes due 2016[1]	–	50
5.18% Series 13 notes due 2017	600	600
2.78% Series 28 notes due 2018	750	750
Floating-rate Series 31 notes due 2019[1]	228	228
1.48% Series 37 notes due 2019[2]	500	–
4.40% Series 20 notes due 2020	300	300
1.62% Series 33 notes due 2020[2]	350	350
1.84% Series 34 notes due 2021	500	–
3.20% Series 25 notes due 2022	600	600
2.77% Series 35 notes due 2026	500	–
7.35% Debentures due 2030	400	400
6.93% Series 2 notes due 2032	500	500
6.35% Series 4 notes due 2034	385	385
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
4.59% Series 29 notes due 2043	435	435
4.17% Series 32 notes due 2044	350	350
5.00% Series 11 notes due 2046	325	325
3.91% Series 36 notes due 2046	350	–
3.72% Series 38 notes due 2047	450	–
4.00% Series 24 notes due 2051	225	225
3.79% Series 26 notes due 2062	310	310
4.29% Series 30 notes due 2064	50	50
Hydro One Inc. long-term debt	10,523	8,723
6.6% Senior Secured Bonds due 2023 (Face value – $112 million)	144	–
4.6% Note Payable due 2023 (Face value – $36 million)	40	–
Great Lakes Power long-term debt	184	–
	10,707	8,723
Add: Net unamortized debt premiums[3]	15	17
Add: Unrealized mark-to-market loss (gain)[2]	(2)	1
Less: Deferred debt issuance costs[3]	(40)	(34)
Total long-term debt	10,680	8,707

1 The interest rates of the floating-rate notes are referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin.

2 The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and $500 million Series 37 notes due 2019 (2015 – loss relates to $50 million of the Series 33 notes due 2020). The unrealized mark-to-market net gain is offset by a $2 million (2015 – $1 million) unrealized mark-to-market net loss (2015 – gain) on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See note 16 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

3 Effective January 1, 2016, deferred debt issuance costs and net unamortized debt premiums were reclassified from other long-term assets and other long-term liabilities, respectively, as an offset to long-term debt upon adoption of ASU 2015-03 (see note 3). Balances as at December 31, 2015 were updated to reflect the retrospective adoption of ASU 2015-03.

The total long-term debt is presented on the consolidated balance sheets as follows:

December 31 *(millions of dollars)*	2016	2015
Current liabilities:		
Long-term debt payable within one year	602	500
Long-term liabilities:		
Long-term debt	10,078	8,207
Total long-term debt	10,680	8,707

In 2016, Hydro One issued $2,300 million (2015 – $350 million) of long-term debt under the MTN Program, and repaid $502 million (2015 – $550 million) of total long-term debt.

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
1 year	602	5.2
2 years	753	2.8
3 years	731	1.4
4 years	653	2.9
5 years	503	1.9
	3,242	2.8
6 – 10 years	1,234	3.3
Over 10 years	6,195	5.2
	10,671	4.3

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
2017	456
2018	425
2019	402
2020	384
2021	370
	2,037
2022-2026	1,703
2027+	4,405
	8,145

16. Fair Value of Financial Instruments and Risk Management

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access.

An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2016 and 2015, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, short-term notes payable, accounts payable, and due to related parties are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2016 and 2015 are as follows:

December 31 (millions of dollars)	2016 Carrying Value	2016 Fair Value	2015 Carrying Value	2015 Fair Value
Long-term debt				
$50 million of MTN Series 33 notes	50	50	51	51
$500 million of MTN Series 37 notes	498	498	–	–
Other notes and debentures	10,132	11,462	8,656	9,942
	10,680	12,010	8,707	9,993

Fair Value Measurements of Derivative Instruments

At December 31, 2016, Hydro One Inc. had interest-rate swaps in the amount of $550 million (2015 – $50 million) that was used to convert fixed-rate debt to floating-rate debt. These swaps are classified as a fair value hedges. Hydro One Inc.'s fair value hedge exposure was equal to about 5% (2015 – 1%) of its total long-term debt. At December 31, 2016, Hydro One Inc. had the following interest-rate swaps designated as fair value hedges:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At December 31, 2016 and 2015, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2016 and 2015 is as follows:

December 31, 2016 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	50	50	50	–	–
	50	50	50	–	–
Liabilities:					
Short-term notes payable	469	469	469	–	–
Long-term debt, including current portion	10,680	12,010	–	12,010	–
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	–	–
	11,151	12,481	471	12,010	–

December 31, 2015 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	94	94	94	–	–
Derivative instruments					
Fair value hedge – interest-rate swap	1	1	1	–	–
	95	95	95	–	–
Liabilities:					
Short-term notes payable	1,491	1,491	1,491	–	–
Long-term debt, including current portion	8,707	9,993	–	9,993	–
	10,198	11,484	1,491	9,993	–

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the fair value levels during the years ended December 31, 2016 and 2015.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the years ended December 31, 2016 or 2015.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2016 and 2015 was not significant.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2016 and 2015, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. At December 31, 2016 and 2015, there was no significant accounts receivable balance due from any single customer.

At December 31, 2016, the Company's provision for bad debts was $35 million (2015 – $61 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2016, approximately 6% (2015 – 6%) of the Company's net accounts receivable were aged more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2016 and 2015, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not significant. At December 31, 2016, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparty.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

At December 31, 2016, accounts payable and accrued liabilities in the amount of $840 million (2015 – $753 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

17. Capital Management

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing access to capital, the Company targets to maintain strong credit quality. At December 31, 2016 and 2015, the Company's capital structure was as follows:

December 31 *(millions of dollars)*	**2016**	2015
Long-term debt payable within one year	**602**	500
Short-term notes payable	**469**	1,491
Less: cash and cash equivalents	**50**	94
	1,021	1,897
Long-term debt	**10,078**	8,207
Preferred shares	**418**	418
Common shares	**5,623**	5,623
Retained earnings	**3,950**	3,806
Total capital	**21,090**	19,951

Hydro One Inc. and Great Lakes Power have customary covenants typically associated with long-term debt. Hydro One Inc.'s long-term debt and credit facility covenants limit permissible debt to 75% of its total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2016, Hydro One Inc. and Great Lakes Power were in compliance with all covenants and limitations.

18. Pension and Post-retirement and Post-employment Benefits

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplementary pension plan, and post-retirement and post-employment benefit plans.

Defined Contribution Pension Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan is mandatory and covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

Hydro One contributions to the DC Plan for the year ended December 31, 2016 were less than $1 million (2015 – $nil). At December 31, 2016, Company contributions payable included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2015 – $nil).

Defined Benefit Pension Plan, Supplementary Pension Plan, and Post-Retirement and Post-Employment Plans

The Pension Plan is a defined benefit contributory plan which covers all regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For Management employees who commenced employment on or after January 1, 2004, and for Society of Energy Professionals-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to Management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2016 of $108 million (2015 – $177 million) were based on an actuarial valuation effective December 31, 2015 (2015 – based on an actuarial valuation effective December 31, 2013) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2017 and 2018 are approximately $105 million and $102 million, respectively, based on the actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings.

Future minimum contributions beyond 2018 will be based on an actuarial valuation effective no later than December 31, 2018. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Hydro One Supplemental Pension Plan (Supplemental Plan) provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for limitations imposed by the *Income Tax Act* (Canada). The Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment benefit plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans is December 31.

Year ended December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
(millions of dollars)	**2016**	2015	**2016**	2015
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**7,683**	7,535	**1,610**	1,582
Current service cost	**144**	146	**42**	43
Employee contributions	**45**	40	**–**	–
Interest cost	**308**	302	**67**	64
Benefits paid	**(354)**	(334)	**(43)**	(47)
Net actuarial loss (gain)	**(52)**	(6)	**14**	(27)
Change due to Hydro One Brampton spin-off	**–**	–	**–**	(5)
Projected benefit obligation, end of year	**7,774**	7,683	**1,690**	1,610
Change in plan assets				
Fair value of plan assets, beginning of year	**6,731**	6,299	**–**	–
Actual return on plan assets	**370**	582	**–**	–
Benefits paid	**(354)**	(334)	**(43)**	(47)
Employer contributions	**108**	177	**43**	47
Employee contributions	**45**	40	**–**	–
Administrative expenses	**(26)**	(33)	**–**	–
Fair value of plan assets, end of year	**6,874**	6,731	**–**	–
Unfunded status	**900**	952	**1,690**	1,610

3 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets as follows:

December 31 *(millions of dollars)*	Pension Benefits **2016**	 2015	Post-Retirement and Post-Employment Benefits **2016**	 2015
Other assets	1[1]	–	–	–
Accrued liabilities	–	–	56	50
Pension benefit liability	900	952	–	–
Post-retirement and post-employment benefit liability	–	–	1,641[2]	1,560
Net unfunded status	899	952	1,697	1,610

[1] Represents the funded status of Great Lakes Power's defined benefit pension plan.

[2] Includes $7 million (2015 – $nil) relating to Great Lakes Power's post-employment benefit plans.

The funded or unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

December 31 *(millions of dollars)*	2016	2015
PBO	7,774	7,683
ABO	7,094	7,020
Fair value of plan assets	6,874	6,731

On an ABO basis, the Pension Plan was funded at 97% at December 31, 2016 (2015 – 96%). On a PBO basis, the Pension Plan was funded at 88% at December 31, 2016 (2015 – 88%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2016 and 2015 for the Pension Plan:

Year ended December 31 *(millions of dollars)*	2016	2015
Current service cost, net of employee contributions	144	146
Interest cost	308	302
Expected return on plan assets, net of expenses	(432)	(406)
Amortization of actuarial losses	96	119
Prior service cost amortization	–	2
Net periodic benefit costs	116	163
Charged to results of operations[1]	48	81

[1] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the year ended December 31, 2016, pension costs of $108 million (2015 – $177 million) were attributed to labour, of which $48 million (2015 – $81 million) was charged to operations, and $60 million (2015 – $96 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2016 and 2015 for the post-retirement and post-employment benefit plans:

Year ended December 31 *(millions of dollars)*	2016	2015
Current service cost, net of employee contributions	42	43
Interest cost	67	64
Amortization of actuarial losses	15	14
Prior service cost amortization	–	–
Net periodic benefit costs	124	121
Charged to results of operations	55	55

Assumptions

The measurement of the obligations of the Plans and the costs of providing benefits under the Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed-income securities.

The following weighted average assumptions were used to determine the benefit obligations at December 31, 2016 and 2015:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	2016	2015	2016	2015
Significant assumptions:				
Weighted average discount rate	3.90%	4.00%	3.90%	4.10%
Rate of compensation scale escalation (long-term)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trends[1]	–	–	4.36%	4.36%

[1] 6.25% per annum in 2017, grading down to 4.36% per annum in and after 2031 (2015 – 6.38% in 2016, grading down to 4.36% per annum in and after 2031).

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2016 and 2015. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

Year ended December 31	2016	2015
Pension Benefits:		
Weighted average expected rate of return on plan assets	6.50%	6.50%
Weighted average discount rate	4.00%	4.00%
Rate of compensation scale escalation (long-term)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	15	13
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	4.10%	4.00%
Rate of compensation scale escalation (long-term)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	15.3	13.8
Rate of increase in health care cost trends[1]	4.36%	4.36%

[1] 6.38% per annum in 2016, grading down to 4.36% per annum in and after 2031 (2015 – 6.52% in 2015, grading down to 4.36% per annum in and after 2031).

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third-party bond yield curve corresponding to each duration. The yield curve is based on "AA" long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of a 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2016 and 2015 is as follows:

December 31 *(millions of dollars)*	**2016**	2015
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	**289**	252
Effect of a 1% decrease in health care cost trends	**(221)**	(196)

The effect of a 1% change in health care cost trends on the service cost and interest cost for the post-retirement and post-employment benefits for the years ended December 31, 2016 and 2015 is as follows:

Year ended December 31 *(millions of dollars)*	**2016**	2015
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	**23**	22
Effect of a 1% decrease in health care cost trends	**(17)**	(16)

The following approximate life expectancies were used in the mortality assumptions to determine the projected benefit obligations for the pension and post-retirement and post-employment plans at December 31, 2016 and 2015:

December 31, 2016				December 31, 2015			
Life expectancy at 65 for a member currently at				Life expectancy at 65 for a member currently at			
Age 65		**Age 45**		Age 65		Age 45	
Male	**Female**	**Male**	**Female**	Male	Female	Male	Female
22	**24**	**23**	**24**	23	25	24	26

Estimated Future Benefit Payments

At December 31, 2016, estimated future benefit payments to the participants of the Plans were:

(millions of dollars)	**Pension Benefits**	Post-Retirement and Post-Employment Benefits
2017	321	56
2018	331	57
2019	340	60
2020	349	62
2021	358	64
2022 through to 2026	1,910	355
Total estimated future benefit payments through to 2026	3,609	654

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

Year ended December 31 *(millions of dollars)*	**2016**	2015
Pension Benefits:		
Actuarial loss (gain) for the year	**35**	(181)
Amortization of actuarial losses	**(96)**	(119)
Prior service cost amortization	**–**	(2)
	(61)	(302)
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	**14**	(27)
Amortization of actuarial losses	**(15)**	(14)
Prior service cost amortization	**–**	–
	(1)	(41)

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2016 and 2015:

Year ended December 31 *(millions of dollars)*	**2016**	2015
Pension Benefits:		
Prior service cost	**–**	–
Actuarial loss	**900**	952
	900	952
Post-Retirement and Post-Employment Benefits:		
Actuarial loss	**243**	240
	243	240

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
(millions of dollars)	**2016**	2015	**2016**	2015
Prior service cost	**–**	–	**–**	–
Actuarial loss	**79**	96	**6**	8
	79	96	**6**	8

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension Plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Human Resource Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

At December 31, 2016, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	55.0	58.7
Debt securities	35.0	33.6
Other[1]	10.0	7.7
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2016, the Pension Plan held $11 million (2015 – $9 million) Hydro One corporate bonds and $450 million (2015 – $420 million) of debt securities of the Province.

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2016 and 2015. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2016 and 2015, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with financial institutions rated at least "A+" by Standard & Poor's Rating Services, DBRS Limited, and Fitch Ratings Inc., and "A1" by Moody's Investors Service, and also by utilizing exposure limits to each counterparty and ensuring that exposure is diversified across counterparties. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following tables present the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2016 and 2015:

December 31, 2016 *(millions of dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	–	20	425	445
Cash and cash equivalents	146	–	–	146
Short-term securities	–	127	–	127
Corporate shares – Canadian	911	–	–	911
Corporate shares – Foreign	2,985	113	–	3,098
Bonds and debentures – Canadian	–	1,943	–	1,943
Bonds and debentures – Foreign	–	193	–	193
Total fair value of plan assets[1]	4,042	2,396	425	6,863

[1] At December 31, 2016, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, $15 million of purchased investments payable, $9 million of pension administration expenses payable, and $7 million of sold investments receivable.

December 31, 2015 *(millions of dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	–	23	301	324
Cash and cash equivalents	191	–	–	191
Short-term securities	–	80	–	80
Corporate shares – Canadian	807	–	–	807
Corporate shares – Foreign	2,931	116	–	3,047
Bonds and debentures – Canadian	–	2,072	–	2,072
Bonds and debentures – Foreign	–	201	–	201
Total fair value of plan assets[1]	3,929	2,492	301	6,722

[1] At December 31, 2015, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, and $18 million relating to accruals for pension administration expense and foreign exchange contracts payable.

See note 16 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2016 and 2015. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 *(millions of dollars)*	**2016**	2015
Fair value, beginning of year	**301**	144
Realized and unrealized gains	**23**	51
Purchases	**151**	106
Sales and disbursements	**(50)**	–
Fair value, end of year	**425**	301

There were no significant transfers between any of the fair value levels during the years ended December 31, 2016 and 2015.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. These sensitivity analyses resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled funds mainly consist of private equity, real estate and infrastructure investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Real estate and infrastructure investments represent funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in real estate include limited partnerships that seek to generate a total return through income and capital growth by investing primarily in global and Canadian limited partnerships. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments. Private equity, real estate and infrastructure valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity and infrastructure investments have been categorized as Level 3 within pooled funds.

Cash equivalents consist of demand cash deposits held with banks and cash held by the investment managers. Cash equivalents are categorized as Level 1.

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities are categorized as Level 2.

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

19. Environmental Liabilities

The following tables show the movements in environmental liabilities for the years ended December 31, 2016 and 2015:

Year ended December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities, January 1	148	59	207
Interest accretion	7	1	8
Expenditures	(11)	(9)	(20)
Revaluation adjustment	(1)	10	9
Environmental liabilities, December 31	143	61	204
Less: current portion	18	9	27
	125	52	177

Year ended December 31, 2015 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities, January 1	172	67	239
Interest accretion	8	2	10
Expenditures	(8)	(11)	(19)
Revaluation adjustment	(24)	1	(23)
Environmental liabilities, December 31	148	59	207
Less: current portion	12	10	22
	136	49	185

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	158	66	224
Less: discounting accumulated liabilities to present value	15	5	20
Discounted environmental liabilities	143	61	204

December 31, 2015 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	168	61	229
Less: discounting accumulated liabilities to present value	20	2	22
Discounted environmental liabilities	148	59	207

At December 31, 2016, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2017	27
2018	26
2019	25
2020	29
2021	36
Thereafter	81
	224

Hydro One records a liability for the estimated future expenditures for land assessment and remediation and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $158 million (2015 – $168 million). These expenditures are expected to be incurred over the period from 2017 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2016 to reduce the PCB environmental liability by $1 million (2015 – $24 million).

Land Assessment and Remediation

The Company's best estimate of the total estimated future expenditures to complete its land assessment and remediation program is $66 million (2015 – $61 million). These expenditures are expected to be incurred over the period from 2017 to 2032. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2016 to increase the land assessment and remediation environmental liability by $10 million (2015 – $1 million).

20. Asset Retirement Obligations

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities and for the decommissioning of specific switching stations located on unowned sites. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2016, Hydro One had recorded asset retirement obligations of $9 million (2015 – $9 million), primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

21. Share Capital

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2016 and 2015, the Company had 595 million common shares issued and outstanding.

The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board of Directors may consider relevant.

Common Share Offerings

In November 2015, Hydro One and the Province completed an initial public offering (IPO) on the Toronto Stock Exchange of approximately 15% of its 595 million outstanding common shares. In April 2016, the Province completed a secondary offering of approximately 83.3 million or 14% common shares of Hydro One on the Toronto Stock Exchange. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2016, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At December 31, 2016, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Hydro One may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Hydro One Board of Directors is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of preferred shares. Holders of Hydro One's preferred shares are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One except that votes may be granted to a series of preferred shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of preferred shares ranks on parity with every other series of preferred shares, and are entitled to a preference over the common shares and any other shares ranking junior to the preferred shares, with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One.

For the period commencing from the date of issue of the Series 1 preferred shares and ending on and including November 19, 2020, the holders of Series 1 preferred shares are entitled to receive fixed cumulative preferential dividends of $1.0625 per share per year, if and when declared by the Board of Directors, payable quarterly. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One on November 20, 2020 and on November 20 of every fifth year thereafter at a redemption price equal to $25.00 for each Series 1 preferred share redeemed, plus any accrued or unpaid dividends. The holders of Series 1 preferred shares will have the right, at their option, on November 20, 2020 and on November 20 of every fifth year thereafter, to convert all or any of their Series 1 preferred shares into Series 2 preferred shares on a one-for-one basis, subject to certain restrictions on conversion. At December 31, 2016, no preferred share dividends were in arrears.

The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board of Directors, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One at a redemption price equal to $25.00 for each Series 2 preferred share redeemed, if redeemed on November 20, 2025 or on November 20 of every fifth year thereafter, or $25.50 for each Series 2 preferred share redeemed, if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 preferred shares will have the right, at their option, on November 20, 2025 and on November 20 of every fifth year thereafter, to convert all or any of their Series 2 preferred shares into Series 1 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

Reorganization

Prior to the completion of the IPO, Hydro One and Hydro One Inc. completed a series of transactions (Pre-IPO Transactions) that resulted in, among other things, on October 31, 2015, Hydro One acquiring all of the issued and outstanding shares of Hydro One Inc. from the Province and issuing new common shares and preferred shares to the Province.

The following tables present the changes to common and preferred shares as a result of Pre-IPO Transactions, as well as the movement in the number of common and preferred shares during the year ended December 31, 2015. There was no movement in common or preferred shares during the year ended December 31, 2016.

		Preferred Shares	
(millions of dollars)	Common Shares	Equity	Temporary Equity
Common shares issued – purchase and cancellation of preferred shares *(c)*	323	–	(323)
Acquisition of Hydro One Inc. *(d)*			
Common shares of Hydro One Inc. acquired by Hydro One	(3,441)	–	–
Common shares of Hydro One issued to Province	3,023	–	–
Preferred shares of Hydro One issued to Province	–	418	–
Common shares issued *(e)*	2,600	–	–
Total Pre-IPO Transactions adjustment	2,505	418	(323)

		Preferred Shares	
(number of shares)	Common Shares	Equity	Temporary Equity
Number of shares – January 1, 2015 *(a)*	100,000	–	12,920,000
Common shares issued *(b)*	100,000	–	–
Pre-IPO Transactions:			
Common shares issued – purchase and cancellation of preferred shares *(c)*	2,640	–	(12,920,000)
Acquisition of Hydro One Inc. *(d)*			
Common shares of Hydro One Inc. acquired by Hydro One	(102,640)	–	–
Common shares of Hydro One issued to Province	12,197,500,000	–	–
Preferred shares of Hydro One issued to Province	–	16,720,000	–
Common shares issued *(e)*	2,600,000,000	–	–
Common shares consolidation *(f)*	(14,202,600,000)	–	–
Number of shares – December 31, 2015	595,000,000	16,720,000	–

(a) At January 1, 2015, all common and preferred shares represent the shares of Hydro One Inc.
(b) On August 31, 2015, Hydro One was incorporated under the *Business Corporations Act* (Ontario) and issued 100,000 common shares to the Province for proceeds of $100,000.
(c) On October 31, 2015, Hydro One Inc. purchased and cancelled 12,920,000 preferred shares of Hydro One Inc. previously held by the Province for cancellation at a price equal to the redemption price of the preferred shares totalling $323 million, which was satisfied by the issuance to the Province of 2,640 common shares of Hydro One Inc.
(d) On October 31, 2015, all of the issued and outstanding common shares of Hydro One Inc. were acquired by Hydro One from the Province in return for 12,197,500,000 common shares of Hydro One and 16,720,000 Series 1 preferred shares of Hydro One.
(e) On November 4, 2015, Hydro One issued 2.6 billion common shares to the Province for proceeds of $2.6 billion.
(f) On November 4, 2015, the common shares of Hydro One were consolidated by way of articles of amendment approved by the Province as sole shareholder so that, after such consolidation, 595,000,000 common shares of Hydro One were issued and outstanding.

Share Ownership Restrictions

The *Electricity Act* imposes share ownership restrictions on securities of Hydro One carrying a voting right (Voting Securities). These restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities, including common shares of the Company (Share Ownership Restrictions). The Share Ownership Restrictions do not apply to Voting Securities held by the Province, nor to an underwriter who holds Voting Securities solely for the purpose of distributing those securities to purchasers who comply with the Share Ownership Restrictions.

22. Dividends

In 2016, preferred share dividends in the amount of $19 million (2015 – $13 million) and common share dividends in the amount of $577 million (2015 – $875 million) were declared. The 2016 common share dividends include $77 million for the post-IPO period from November 5 to December 31, 2015, and $500 million for the year ended December 31, 2016.

In August 2015, Hydro One declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton (see note 4).

23. Earnings Per Share

Basic earnings per common share (EPS) is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding. Diluted EPS is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding adjusted for the effects of potentially dilutive stock-based compensation plans, including the share grant plans and the Long-term Incentive Plan, which are calculated using the treasury stock method.

Year ended December 31	**2016**	2015
Net income attributable to common shareholders *(millions of dollars)*	**721**	690
Weighted average number of shares		
Basic	**595,000,000**	496,272,733
Effect of dilutive stock-based compensation plans *(Note 24)*	**1,700,823**	94,691
Diluted	**596,700,823**	496,367,424
EPS		
Basic	**$1.21**	$1.39
Diluted	**$1.21**	$1.39

Pro forma Adjusted non-GAAP Basic and Diluted EPS

The following pro forma adjusted non-GAAP basic and diluted EPS has been prepared by management on a supplementary basis which assumes that the total number of common shares outstanding was 595,000,000 in each of the years ended December 31, 2016 and 2015. The supplementary pro forma disclosure is used internally by management subsequent to the IPO of Hydro One to assess the Company's performance and is considered useful because it eliminates the impact of a different number of shares outstanding and held by the Province prior to the IPO. EPS is considered an important measure and management believes that presenting it for all periods based on the number of outstanding shares on, and subsequent to, the IPO provides users with a comparable basis to evaluate the operations of the Company.

Year ended December 31 (unaudited)	**2016**	2015
Net income attributable to common shareholders *(millions of dollars)*	**721**	690
Pro forma weighted average number of common shares		
Basic	**595,000,000**	595,000,000
Effect of dilutive stock-based compensation plans *(Note 24)*	**1,700,823**	94,691
Diluted	**596,700,823**	595,094,691
Pro forma adjusted non-GAAP EPS		
Basic	**$1.21**	$1.16
Diluted	**$1.21**	$1.16

The above pro forma adjusted non-GAAP basic and diluted EPS does not have any standardized meaning in US GAAP.

24. Stock-based Compensation

Share Grant Plans

At December 31, 2016, Hydro One had two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (the PWU Share Grant Plan) and one for the benefit of certain members of The Society of Energy Professionals (the Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the Power Workers' Union annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan begins on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,979,062 common shares were granted under the PWU Share Grant Plan.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of The Society of Energy Professionals annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan begins on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,433,292 common shares were granted under the Society Share Grant Plan.

The fair value of the Hydro One Limited 2015 share grants of $111 million was estimated based on the grant date share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. No shares were granted under the Share Grant Plans in 2016. Total share based compensation recognized during 2016 was $21 million (2015 – $10 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during years ended December 31, 2016 and 2015 is presented below:

Year ended December 31, 2016	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding – January 1, 2016	5,412,354	$20.50
Granted (non-vested)	–	–
Forfeited	(77,939)	$20.50
Share grants outstanding – December 31, 2016	5,334,415	$20.50

Year ended December 31, 2015	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding – January 1, 2015	–	–
Granted (non-vested)	5,412,354	$20.50
Share grants outstanding – December 31, 2015	5,412,354	$20.50

Directors' DSU Plan

Under the Company's Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

Year ended December 31 *(number of DSUs)*	2016	2015
DSUs outstanding – January 1	20,525	–
DSUs granted	78,558	20,525
DSUs outstanding – December 31	99,083	20,525

For the year ended December 31, 2016, an expense of $2 million (2015 – less than $1 million) was recognized in earnings with respect to the DSU Plan. At December 31, 2016, a liability of $2 million (December 31, 2015 – less than $1 million), related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $23.58 and is included in accrued liabilities on the Consolidated Balance Sheets.

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One established an Employee Share Ownership Plan (ESOP). Under the ESOP, certain eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One. The Company matches 50% of the employee's contributions, up to a maximum Company contribution of $25,000 per calendar year. In 2016, Company contributions made under the ESOP were $2 million (2015 – $nil).

Long-term Incentive Plan

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One and its subsidiaries, and all equity-based awards will be settled in newly issued shares of Hydro One from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One.

The LTIP provides flexibility to award a range of vehicles, including restricted share units (RSUs), performance share units (PSUs), stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

During 2016, the Company granted awards under its LTIP, consisting of PSUs and RSUs, all of which are equity settled, as follows:

Year ended December 31, 2016	Number of PSUs	Number of RSUs
Units outstanding – January 1, 2016	–	–
Units granted	235,420	258,970
Units forfeited	(4,820)	(4,820)
Units outstanding – December 31, 2016	230,600	254,150

The grant date total fair value of the awards was $12 million (2015 – $nil). The compensation expense recognized by the Company relating to these awards during 2016 was $3 million (2015 – $nil).

25. Noncontrolling Interest

On December 16, 2014, transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the Saugeen Ojibway Nation (SON) acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. The SON's initial investment in B2M LP consists of $50 million of Class A units and $22 million of Class B units.

The Class B units have a mandatory put option which requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), Hydro One purchase the Class B units of B2M LP for net book value on the redemption date. The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity.

The following tables show the movements in noncontrolling interest for the years ended December 31, 2016 and 2015:

Year ended December 31, 2016 *(millions of dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest – January 1, 2016	23	52	75
Distributions to noncontrolling interest	(3)	(6)	(9)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest – December 31, 2016	22	50	72

Year ended December 31, 2015 *(millions of dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest – January 1, 2015	21	49	70
Distributions to noncontrolling interest	(1)	(4)	(5)
Net income attributable to noncontrolling interest	3	7	10
Noncontrolling interest – December 31, 2015	23	52	75

26. Related Party Transactions

The Province is the majority shareholder of Hydro One. The IESO, Ontario Power Generation Inc. (OPG), OEFC, OEB, and Hydro One Brampton are related parties to Hydro One because they are controlled or significantly influenced by the Province.

		Year ended December 31	
		2016	2015
Related Party	Transaction	*(millions of dollars)*	
Province[1]	Dividends paid	451	888
	Common shares issued[2]	–	2,600
	IPO costs subsequently reimbursed by the Province[3]	–	7
IESO	Power purchased	2,096	2,318
	Revenues for transmission services	1,549	1,548
	Distribution revenues related to rural rate protection	125	127
	Distribution revenues related to the supply of electricity to remote northern communities	32	32
	Funding received related to Conservation and Demand Management programs	63	70
OPG	Power purchased	6	11
	Revenues related to provision of construction and equipment maintenance services	5	7
	Costs expensed related to the purchase of services	1	1
OEFC	Payments in lieu of corporate income taxes[4]	–	2,933
	Power purchased from power contracts administered by the OEFC	1	6
	Indemnification fee paid (terminated effective October 31, 2015)	–	8
OEB	OEB fees	11	12
Hydro One Brampton[1]	Revenues from management, administrative and smart meter network services	3	1

1 On August 31, 2015, Hydro One Inc. completed the spin-off of its subsidiary, Hydro One Brampton, to the Province.

2 On November 4, 2015, Hydro One issued common shares to the Province for proceeds of $2.6 billion.

3 In 2015, Hydro One incurred certain IPO related expenses totalling $7 million, which were subsequently reimbursed to the Company by the Province.

4 In 2015, Hydro One made PILs to the OEFC totalling $2.9 billion, including Departure Tax of $2.6 billion.

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 *(millions of dollars)*	2016	2015
Due from related parties	158	191
Due to related parties[1]	(147)	(138)

[1] Included in due to related parties at December 31, 2016 are amounts owing to the IESO in respect of power purchases of $143 million (2015 – $134 million).

27. Consolidated Statements of Cash Flows

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2016	2015
Accounts receivable	(60)	245
Due from related parties	33	33
Materials and supplies	2	2
Prepaid expenses and other assets	(15)	4
Accounts payable	19	(23)
Accrued liabilities	53	(15)
Due to related parties	9	(89)
Accrued interest	9	(4)
Long-term accounts payable and other liabilities	6	–
Post-retirement and post-employment benefit liability	78	60
	134	213

Capital Expenditures

The following table reconciles between investments in property, plant and equipment and the amount presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2016	2015
Capital investments in property, plant and equipment	(1,630)	(1,623)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	30	28
Capital expenditures – property, plant and equipment	(1,600)	(1,595)

The following table reconciles between investments in intangible assets and the amount presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2016	2015
Capital investments in intangible assets	(67)	(40)
Net change in accruals included in capital investments in intangible assets	6	3
Capital expenditures – intangible assets	(61)	(37)

Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2016, capital contributions from these reassessments totalled $21 million (2015 – $57 million), which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments.

Supplementary Information

Year ended December 31 *(millions of dollars)*	2016	2015
Net interest paid	**418**	416
Income taxes / PILs paid	**32**	2,933

28. Contingencies

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. A certification motion in the class action is pending. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2016, the Company paid approximately $1 million (2015 – $1 million) in respect of consents obtained. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

29. Commitments

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

December 31, 2016 *(millions of dollars)*	2017	2018	2019	2020	2021	Thereafter
Outsourcing agreements	165	102	94	2	2	9
Long-term software/meter agreement	17	17	16	17	1	5
Operating lease commitments	11	10	6	10	3	2

Outsourcing Agreements

Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., provides services to Hydro One, including settlements, source to pay services, pay operations services, information technology, finance and accounting services. The agreement with Inergi for these services expires in December 2019. In addition, Inergi provides customer service operations outsourcing services to Hydro One. The agreement for these services expires in February 2018.

Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The agreement with Brookfield for these services expires in December 2024.

Long-term software/meter agreement

Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (collectively Trilliant) provide services to Hydro One for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licences, as well as certain professional services. The agreement with Trilliant for these services expires in December 2025, but Hydro One has the option to renew for an additional term of five years at its sole discretion.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have typical terms of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. During the year ended December 31, 2016, the Company made lease payments totalling $11 million (2015 – $7 million).

Other Commitments

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2016, Hydro One Inc. provided prudential support to the IESO on behalf of its subsidiaries using parental guarantees of $329 million (2015 – $329 million), and on behalf of a distributor using guarantees of $1 million (2015 – $1 million). In addition, as at December 31, 2016, Hydro One Inc. provided letters of credit in the amount of $24 million (2015 – $15 million), including $17 million (2015 – $15 million) to the IESO. The IESO could draw on these guarantees and/or letters of credit if these subsidiaries or distributor fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for Hydro One Inc.'s liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One Inc. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One Inc. is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure Hydro One Inc.'s liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit. At December 31, 2016, Hydro One Inc. had letters of credit of $150 million (2015 – $139 million) outstanding relating to retirement compensation arrangements.

30. Segmented Reporting

Hydro One has three reportable segments:

- The Transmission Business, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Business, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Business, which includes certain corporate activities and the operations of the Company's telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see note 2).

Year ended December 31, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,584	4,915	53	6,552
Purchased power	–	3,427	–	3,427
Operation, maintenance and administration	382	608	79	1,069
Depreciation and amortization	390	379	9	778
Income (loss) before financing charges and income taxes	812	501	(35)	1,278
Capital investments	988	703	6	1,697

Year ended December 31, 2015 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,536	4,949	53	6,538
Purchased power	–	3,450	–	3,450
Operation, maintenance and administration	414	633	88	1,135
Depreciation and amortization	374	380	5	759
Income (loss) before financing charges and income taxes	748	486	(40)	1,194
Capital investments	943	711	9	1,663

Total Assets by Segment:

December 31 *(millions of dollars)*	2016	2015
Transmission	13,007	12,045
Distribution	9,337	9,200
Other	3,007	3,049
Total assets	25,351	24,294

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

31. Subsequent Events

Dividends

On February 9, 2017, preferred share dividends in the amount of $4 million and common share dividends in the amount of $125 million ($0.21 per common share) were declared.

BOARD OF DIRECTORS
& SENIOR LEADERSHIP TEAM

For detailed biographical information of Hydro One Limited board members and senior leadership, go to
▶ HydroOne.com/Investors

BOARD OF DIRECTORS

1 **David Denison,** O.C., FCPA, FCA
Chair of the Board

2 **Ian Bourne,** ICD.D, F.ICD
Board Chair, Ballard Power Systems

3 **Charles Brindamour**
CEO, Intact Financial Corporation

4 **Marcello (Marc) Caira**
Vice Chairman,
Restaurants Brands International

5 **Christie Clark,** FCA, FCPA
Director, Loblaw Companies

6 **George Cooke**
Board Chair,
OMERS Administration Corp

7 **Margaret (Marianne) Harris**
Board Chair, IIROC

8 **James Hinds**
Former Board Chair, IESO and OPA

9 **Kathryn J. Jackson,** PH.D
Director, Portland General Electric

10 **Roberta Jamieson** O.C., C.M., I.P.C, LL.B, LL.D (HON)
President and CEO, Indspire

11 **Hon. Frances L. Lankin,** O.C., P.C., C.M.
Member of Senate of Canada

12 **Philip S. Orsino,** O.C., FCPA, FCA
Director, Bank of Montreal

13 **Jane Peverett,** FCMA, ICD.D
Director, Canadian Imperial
Bank of Commerce

14 **Gale Rubenstein**
Partner, Goodmans LLP

15 **Mayo Schmidt**
President and CEO, Hydro One Limited

SENIOR LEADERSHIP TEAM

15 **Mayo Schmidt**
President and CEO

16 **Paul H. Barry**
EVP, Strategy
& Corporate Development

17 **Greg Kiraly**
Chief Operating Officer

18 **Judy McKellar**
EVP, Chief Human
Resources Officer

19 **Ferio Pugliese**
EVP, Customer Care
& Corporate Affairs

20 **James (Jamie) Scarlett**
EVP, Chief Legal Officer

21 **Michael Vels**
Chief Financial Officer

CORPORATE & SHAREHOLDER INFORMATION

CORPORATE OFFICES

483 Bay Street, South Tower
Toronto, Ontario, M5G 2P5
1.416.345.5000
www.HydroOne.com

CUSTOMER INQUIRIES

Customer Service:
1.888.664.9376 or
CustomerCommunications@HydroOne.com
Report an Emergency (24 hours):
1.800.434.1235

SHAREHOLDER SERVICES

If you are a registered shareholder and have inquiries regarding your account, wish to change your name or address, or have questions about dividends, duplicate mailings, lost stock certificates, share transfers or estate settlements, contact our transfer agent and registrar:
Computershare Trust Company of Canada
100 University Avenue, 8th Floor
Toronto, ON M5J 2Y1
1.514.982.7555 or 1.800.564.6253
service@computershare.com

INSTITUTIONAL INVESTORS AND ANALYSTS

Institutional investors, securities analysts and others requiring additional financial information can visit HydroOne.com/Investors or contact us at:
1.416.345.6867
Investor.Relations@HydroOne.com or
Bruce.Mann@HydroOne.com

MEDIA INQUIRIES

1.416.345.6868 or 1.877.506.7584
Media.Relations@HydroOne.com

SUSTAINABILITY

Hydro One is committed to continuing to grow responsibly and we focus our social and environmental sustainability efforts where we can make the most meaningful impacts on both. To learn more, visit HydroOne.com/OurCommitment

STOCK EXCHANGE LISTING

Toronto Stock Exchange (TSX): H
(CUSIP #448811208)

H LISTED ON TMX Toronto Stock Exchange

EQUITY INDEX INCLUSIONS

Dow Jones Select Utilities (Canada) Index
FTSE All-World Index Series
MSCI World (Canada) Index
S&P/TSX Composite Index
S&P/TSX Utilities Index
S&P/TSX Composite Dividend Index
S&P/TSX Composite Low Volatility Index

DEBT SECURITIES

For details of the public debt securities of Hydro One and its subsidiaries, please refer to the *"Debt Information"* section under HydroOne.com/Investors

INDEPENDENT AUDITORS

KPMG LLP

ON-LINE INFORMATION

Hydro One is committed to open and full financial disclosure and best practices in corporate governance. We invite you to visit the Investor Relations section of HydroOne.com/InvestorRelations where you will find additional information about our business, including events and presentations, news releases, regulatory filings, governance practices, corporate social responsibility and our continuous disclosure materials, including quarterly financial releases, annual information forms and management information circulars. You may also subscribe to our news by email to automatically receive Hydro One news releases electronically.

COMMON SHARE DIVIDEND INFORMATION

2017 Expected Dividend Dates

Record Date*:	Payment Date*:
March 14, 2017	March 31, 2017
June 13, 2017	June 30, 2017
September 12, 2017	September 29,2017
December 12, 2017	December 29, 2017

** Subject to Board approval*

Unless indicated otherwise, all common share dividends paid by Hydro One are designated as "eligible" dividends for the purposes of the *Income Tax Act* (Canada) and any similar provincial legislation.

DIVIDEND REINVESTMENT PLAN (DRIP)

Hydro One offers a convenient dividend reinvestment program for eligible shareholders to purchase additional Hydro One shares by reinvesting their cash dividends without incurring brokerage or administration fees. For plan information and enrolment materials or to learn more about the Hydro One DRIP, visit HydroOne.com/DRIP or Computershare Trust Company of Canada at InvestorCentre.com/HydroOne

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LINKEDIN
linkedin.com/company/hydro-one

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▶ HydroOne.com/Investors

CAUTION REGARDING FORWARD-LOOKING INFORMATION AND OTHER RISKS

This annual report includes forward-looking statements about the financial condition, plans and prospects of Hydro One that involve risks and uncertainties and non-GAAP measures that are detailed in the "Risk Management and Risk Factors", "Forward-Looking Statements and Information", and "Non-GAAP Measures" sections of the MD&A contained herein, which should be read in conjunction with all sections of this document.

IR magazine AWARDS 2016 CANADA WINNER

IFR AWARDS 2016

PR News Platinum PR Awards Winner

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HYDRO ONE LIMITED IS ONE OF NORTH AMERICA'S LARGEST ELECTRIC UTILITIES, WITH A REGULATED TRANSMISSION GRID TRANSMITTING 98 PERCENT OF ONTARIO'S ELECTRIC POWER, AND A REGULATED LOCAL DISTRIBUTION OPERATION DELIVERING ELECTRICITY TO MORE THAN 1.3 MILLION RESIDENTIAL AND BUSINESS CUSTOMERS ACROSS 75 PERCENT OF THE GEOGRAPHY OF THE PROVINCE.

hydroOne

HydroOne.com

ANNUAL INFORMATION FORM

FOR HYDRO ONE LIMITED

FOR THE YEAR ENDED DECEMBER 31, 2016

March 27, 2017

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GLOSSARY

When used in this annual information form, the following terms have the meanings set forth below unless expressly indicated otherwise:

"**$**" or "**dollar**" means Canadian Dollars.

"**2015 Underwriting Agreement**" has the meaning given to it under "Material Contracts".

"**2016 Underwriting Agreement**" has the meaning given to it under "Material Contracts".

"**Annual MD&A**" means management's discussion and analysis for Hydro One Limited for the year ended December 31, 2016, as filed on SEDAR under Hydro One Limited's profile at www.sedar.com.

"**Board**" means the Board of Directors of Hydro One Limited.

"**CDM**" means conservation and demand management.

"**common shares**" means the common shares in the capital of Hydro One Limited.

"**Custom IR Method**" has the meaning given to it under "Business of Hydro One – Transmission Business – Regulation – Transmission Rate Setting.

"**DMS**" has the meaning given to it under "Business of Hydro One – Distribution Business – Regulation – Capital Expenditures".

"**Electricity Act**" means the *Electricity Act, 1998* (Ontario).

"**Great Lakes Power**" means Great Lakes Power Transmission LP.

"**Governance Agreement**" means the governance agreement dated November 5, 2015 between Hydro One Limited and the Province.

"**GWh**" means gigawatt-hours.

"**Haldimand Hydro**" means Haldimand County Utilities Inc.

"**Hydro One**" or the "**Company**" have the meanings given to such terms set out under "Presentation of Information".

"**Hydro One Limited**" has the meaning given to it under "Presentation of Information".

"**Hydro One Inc.**" has the meaning given to it under "Presentation of Information".

"**IESO**" means the Independent Electricity System Operator.

"**kV**" means kilovolt.

"**kW**" means kilowatt.

"**management**" has the meaning given to it under "Presentation of Information".

"**Market Rules**" means the rules made under section 32 of the Electricity Act that are administered by the IESO.

"**NERC**" has the meaning given to it under "The Electricity Industry in Ontario – Regulation of Transmission and Distribution – IESO".

"**Norfolk Power**" means Norfolk Power Inc.

"**NPCC"** has the meaning given to it under "The Electricity Industry in Ontario – Regulation of Transmission and Distribution – IESO".

"**OBCA**" means the *Business Corporations Act* (Ontario).

"**OEB**" means the Ontario Energy Board.

"**Ontario**" or the "**province**" has the meaning given to it under "Presentation of Information".

"**Ontario Energy Board Act**" means the *Ontario Energy Board Act, 1998* (Ontario).

"**Orillia Power**" means Orillia Power Distribution Corporation.

"**PCB**" means polychlorinated biphenyls.

"**Province**" has the meaning given to it under "Presentation of Information".

"**Registration Rights Agreement**" means the registration rights agreement dated November 5, 2015 between Hydro One Limited and the Province.

"**Removal Notice**" has the meaning given to it under "Agreements with Principal Shareholder – Governance Agreement – Governance Matters – Election and Replacement of Directors – Province's Right to Replace the Board".

"**Reserve**" means a "reserve" as that term is defined in the *Indian Act* (Canada).

"**Revenue Cap Index**" has the meaning given to it under "Business of Hydro One – Transmission Business – Regulation – Transmission Rate Setting".

"**RRF**" has the meaning given to it under "Business of Hydro One – Distribution Business – Regulation – Distribution Rates".

"**Share Ownership Restrictions**" has the meaning given to it under "The Electricity Industry in Ontario – Legislative Provisions Specific to Hydro One – 10% Ownership Restriction".

"**shares**" has the meaning given to it under "Agreements with Principal Shareholder – Registration Rights Agreement – Demand Registration".

"**Special Board Resolution**" has the meaning given to it under "Agreements with Principal Shareholder – Governance Agreement – Governance Matters – Board Approvals Requiring a Special Resolution of the Directors".

"**Specified Provincial Entity**" has the meaning given to it under "Agreements with Principal Shareholder – Governance Agreement – Governance Matters – Nomination of Directors – Independence".

"**trust assets**" has the meaning given to it under "Interests of Management and Others in Material Transactions – Relationships with the Province and Other Parties – Transfer Orders".

"**TS**" means transmission station.

"**TSX**" means the Toronto Stock Exchange.

"**TWh**" means terawatt-hours.

"**U.S. GAAP**" means United States Generally Accepted Accounting Principles.

"**Voting Securities**" means a security of Hydro One Limited carrying a voting right either under all circumstances or under some circumstances that have occurred and are continuing.

"**Woodstock Hydro**" means Woodstock Hydro Holdings Inc.

PRESENTATION OF INFORMATION

Unless otherwise specified, all information in this annual information form is presented as at December 31, 2016.

Capitalized terms used in this annual information form are defined under "Glossary". Words importing the singular number include the plural, and vice versa, and words importing any gender include all genders. The Annual MD&A and the audited consolidated financial statements of Hydro One Limited as at and for the year ended December 31, 2016, are specifically incorporated by reference into and form an integral part of this annual information form. Copies of these documents have been filed with the Canadian securities regulatory authorities and are available on SEDAR at www.sedar.com.

Unless otherwise noted or the context otherwise requires, references to "**Hydro One**" or the "**Company**" refer to Hydro One Limited and its subsidiaries taken together as a whole. References to "**Hydro One Inc.**" refer only to Hydro One Inc. and references to "**Hydro One Limited**" refer only to Hydro One Limited.

In addition, "**Province**" refers to the Province of Ontario as a provincial government entity, and "**Ontario**" or the "**province**" in lower case type refers to the Province of Ontario as a geographical area.

References to "**management**" in this annual information form mean the persons who are identified as executive officers of Hydro One Limited and its subsidiaries, as applicable, in this annual information form. Any statements made by or on behalf of management are made in such persons' respective capacities as executive officers of Hydro One Limited and its subsidiaries, as applicable, and not in their personal capacities. See "Directors and Officers" for more information.

This annual information form refers to certain terms commonly used in the electricity industry, such as "**rate-regulated**", "**rate base**" and "**return on equity**". For a description of these terms, see "Rate-Regulated Utilities". Rate base is an amount that a utility is required to calculate for regulatory purposes, and refers to the net book value of the utility's assets for regulatory purposes. Return on equity is a percentage that is set or approved by a utility's regulator and represents the rate of return that a regulator allows the utility to earn on the equity component of the utility's rate base.

In this annual information form, all dollar amounts are expressed in Canadian dollars unless otherwise indicated. All references to "$" or "dollars" refers to Canadian dollars. Hydro One Limited and Hydro One Inc. prepare and present their financial statements in accordance with U.S. GAAP.

FORWARD-LOOKING INFORMATION

Certain information in this annual information form contains "forward-looking information" within the meaning of applicable Canadian securities laws. Forward-looking information in this annual information form is based on current expectations, estimates, forecasts and projections about Hydro One's business and the industry in which Hydro One operates and includes beliefs of and assumptions made by management. Such statements include, but are not limited to, statements related to: the Company's transmission and distribution rate applications, and resulting rates and impacts; expected impacts of changes to the electricity industry; the Company's maturing debt and standby credit facilities; expectations regarding the Company's financing activities; credit ratings; ongoing and planned projects and/or initiatives, including expected results and timing; expected future capital expenditures, the nature and timing of these expenditures, including the Company's plans for sustaining and development capital expenditures for its distribution and transmission systems; expectations regarding allowed return on equity; expectations regarding the ability of the Company to recover expenditures in future rates; the OEB; future pension contributions, the pension plan and valuations; expectations regarding the ability to negotiate collective agreements consistent with rate orders and to maintain stable outsourcing arrangements; expectations related to work force demographics; expectations regarding taxes;

occupational rights; expectations regarding load growth; the regional planning process; expectations related to Hydro One's CDM requirements and targets; the Company's customer focus and related initiatives; statements related to the Company's relationships with First Nations and Métis communities; statements related to environmental matters, and the Company's expected future environmental expenditures; expectations related to the effect of interest rates; the Company's reputation; cyber and data security; the Company's relationship with the Province; future sales of shares of Hydro One; acquisitions, including the Company's acquisition of Orillia Power; expectations regarding the Governance Agreement and other agreements with the Province; expectations regarding the manner in which Hydro One will operate; expectations regarding Hydro One's dividend policy and the Company's intention to declare and pay dividends, including the target payout ratio of 70% to 80% of net income; and legal proceedings in which Hydro One is currently involved.

Words such as "aim", "could", "would", "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "target", and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Hydro One does not intend, and it disclaims any obligation to update any forward-looking information, except as required by law.

The forward-looking information in this annual information form is based on a variety of factors and assumptions including, but not limited to: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for Hydro One's distribution and transmission businesses; no unfavourable changes in environmental regulation; continued use of U.S. GAAP; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to Hydro One, including information obtained from third-party sources. Actual results may differ materially from those predicted by such forward-looking information. While Hydro One does not know what impact any of these differences may have, Hydro One's business, results of operations, financial condition and credit stability may be materially adversely affected if any such differences occur. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information include, among other things:

- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets

located on Reserves;

- the risks associated with information system security and with maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- the risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using U.S. GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under the heading "Risk Management and Risk Factors" in the Annual MD&A. You should review such section in detail, including the matters referenced therein.

In addition, Hydro One cautions the reader that information provided in this annual information form regarding Hydro One's outlook on certain matters, including potential future expenditures, is provided in order to give context to the nature of some of Hydro One's future plans and may not be appropriate for other purposes.

ELECTRICITY INDUSTRY OVERVIEW

General Overview

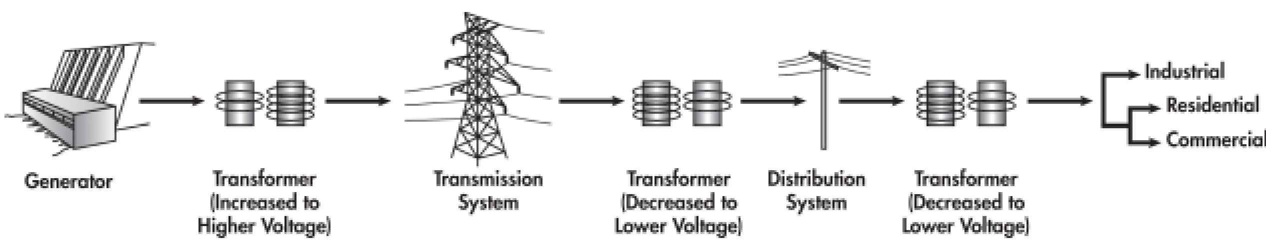
The electricity industry is made up of businesses that generate, transmit, distribute and sell electricity. While traditionally a mature and stable industry, innovation and technological change are expected to have a significant impact on the industry in the foreseeable future. Hydro One's business is focused on the transmission and distribution of electricity.

- Transmission refers to the delivery of electricity over high voltage lines, typically over long distances, from generating stations to local areas and large industrial customers.

- Distribution refers to the delivery of electricity over low voltage power lines to end users such as homes, businesses and institutions.

Overview of an Electricity System

The basic configuration of a typical electricity system showing electricity generation, transmission and distribution is illustrated in the following diagram:



Transmission and distribution networks are sometimes referred to as the "electricity grid" or simply "the grid". For simplicity, the diagram above does not show customers directly connected to the transmission system or distributed generation sources or other distributors that may be connected to the distribution system.

THE ELECTRICITY INDUSTRY IN ONTARIO

Regulation of Transmission and Distribution

General

The Electricity Act and the Ontario Energy Board Act establish the general legislative framework for Ontario's electricity market. The activities of transmitters and distributors in Ontario are overseen by three main regulatory authorities: (i) the OEB, (ii) the IESO, and (iii) the National Energy Board.

Ontario Energy Board

The OEB is an independent and impartial public regulatory agency. The Ontario Energy Board Act provides the OEB with the authority to regulate Ontario's electricity market, including the activities of transmitters and distributors.

The OEB has the following objectives in relation to the electricity industry:

- to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service,

- to promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry,

- to promote electricity conservation and demand management in a manner consistent with the policies of the Province, including having regard to the consumer's economic circumstances,

- to facilitate the implementation of a smart grid in Ontario, and

- to promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Province, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

The OEB is responsible for, among other things, approving transmission and distribution rates in Ontario. It also approves the construction, expansion, or reinforcement of transmission lines greater than two kilometres in length, as well as mergers, acquisitions, amalgamations and divestitures involving distributors, transmitters and other entities which it licenses. The activities of transmitters and distributors are subject to the conditions of their licenses and a number of industry codes issued by the OEB. These codes and other requirements prescribe minimum standards of conduct and service for licensed participants in the electricity market.

IESO

The IESO manages the operation and reliability of Ontario's bulk power system and administers the wholesale electricity market. It is governed by a board whose chair and directors are appointed by the Province. The IESO also coordinates province-wide conservation efforts.

Transmitters and other wholesale market participants must comply with the Market Rules issued by the IESO. The Market Rules require transmitters to comply with mandatory North American reliability standards for transmission issued by the North American Electric Reliability Corporation ("NERC") and the Northeast Power Coordinating Council, Inc. ("NPCC"). The IESO enforces these reliability standards and coordinates with system operators and reliability agencies in other jurisdictions to ensure energy adequacy and security across the interconnected bulk electricity system in North America.

National Energy Board

The National Energy Board is an independent federal regulatory agency, governed by the *National Energy Board Act* (Canada) and has jurisdiction over the construction and operation of international power lines, as well as interprovincial lines that are designated as being under federal jurisdiction (of which there are currently none). As Hydro One owns and operates 11 active international power lines connecting Ontario's transmission system with transmission systems in Michigan, Minnesota and New York, Hydro One is required to hold several certificates and permits issued by the National Energy Board and is subject to its mandatory electricity reliability standards and reporting requirements.

Transmission

Transmission companies own and operate transmission systems that deliver electricity over high voltage lines. Hydro One's transmission system accounts for approximately 98% of Ontario's electricity transmission capacity based on the revenues approved by the OEB. The Company's transmission system is interconnected to systems in Manitoba, Michigan, Minnesota, New York and Quebec and is part of the North American electricity grid's Eastern Interconnection. The Eastern Interconnection is a contiguous electricity transmission system that extends from Manitoba to Florida and from east of the Rocky Mountains to the North American east coast. Being part of the Eastern Interconnection provides benefits to Ontario, such as greater security and stability for Ontario's transmission system, emergency support when there are generation constraints or shortages in Ontario, and the ability to exchange electricity with other jurisdictions.

Distribution

Distributors own and operate distribution systems that deliver electricity over power lines at voltages of 50kV or less to end users. In Ontario, as at December 31, 2015, 71 local distribution companies provided electricity to approximately five million customers. During 2016, Hydro One completed integration of two local distribution companies. The distribution industry in Ontario is fragmented, with the 15 largest local distribution companies accounting for approximately 78% of the province's customers.

Through its wholly-owned subsidiary Hydro One Inc., Hydro One owns the largest local distribution company in Ontario, which serves over 1.3 million, predominantly rural customers, or approximately 26% of the total number of customers in Ontario.

A local distribution company is responsible for distributing electricity to customers in its OEB-licensed service territory, and in some cases to other distributors. A service territory may cover large portions or all of a particular municipality, or an otherwise-defined geographic area. Distribution customers include homes, commercial and industrial businesses and institutions such as governments, schools and hospitals.

Legislative Provisions Specific to Hydro One

In addition to legislation in Ontario that impacts all transmitters and distributors, there is legislation that is specific to Hydro One. Specifically, the Electricity Act requires Hydro One's head office and principal grid control centre to be maintained in Ontario, restricts the disposition of substantially all of its OEB-regulated transmission or distribution business, prohibits any change to its jurisdiction of incorporation, requires the Company to have an ombudsman, contains a 10% ownership restriction with respect to Voting Securities and restricts the Province from selling Voting Securities if it would own less than 40% of the Voting Securities of any class or series as a result of the sale.

Ombudsman

The Electricity Act requires the Company to have an ombudsman to act as a liaison with customers and to establish procedures for the ombudsman to inquire into and report to the Board on matters raised with the ombudsman by or on behalf of customers. See "General Development of the Business – Customer Focus – Ombudsman" for more information.

10% Ownership Restriction

The Electricity Act imposes share ownership restrictions on the Voting Securities. These restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities, including common shares of the Company (the "Share Ownership Restrictions"). The Share Ownership Restrictions do not apply to Voting Securities held by the Province, nor to an underwriter who holds Voting Securities solely for the purpose of distributing those securities to purchasers who comply with the Share Ownership Restrictions. The articles of Hydro One Limited provide for comprehensive enforcement mechanisms that are applicable in the event of a contravention of the Share Ownership Restrictions.

Maintenance of 40% Ownership

As of December 31, 2016, the Province owned approximately 70.1% of Hydro One Limited's common shares. The Province has indicated that it intends to sell further common shares over time, until it holds approximately 40% of Hydro One Limited. See the Annual MD&A under the heading "Risk Management and Risk Factors" for more information.

The Electricity Act restricts the Province from selling Voting Securities (including common shares of Hydro One Limited) if it would own less than 40% of the outstanding number of Voting Securities of that class or series after the sale. If as a result of the issuance of additional Voting Securities by Hydro One Limited, the Province owns less than 40% of the outstanding number of Voting Securities of any class or series, the Province must, subject to the approval of the Lieutenant Governor in Council and the necessary appropriations from the Legislature, take steps to acquire as many Voting Securities of that class or series as are necessary to increase the Province's ownership to not less than 40% of the outstanding number of Voting Securities of that class or series. The manner in which, and the time by which, the Province must acquire these additional Voting Securities will be determined by the Lieutenant Governor in Council.

The Province has been granted pre-emptive rights by Hydro One Limited to assist it in meeting its ownership requirements under the Electricity Act as described under "Agreements with Principal Shareholder – Governance Agreement – Other Matters – Pre-emptive Rights".

Elimination of Certain Legislation With Respect to Hydro One

In 2015, prior to completion of the initial public offering of Hydro One Limited, Hydro One Inc. and its subsidiaries ceased to be subject to a number of Ontario statutes that apply to entities owned by the Province. Hydro One Limited is similarly not subject to those statutes. In making the transition, the Auditor General of Ontario, the Financial Accountability Officer, the Information and Privacy Commissioner and the Provincial Ombudsman continued to exercise certain of their powers with respect to the Company in certain limited circumstances until December 4, 2015. The Information and Privacy Commissioner could also continue to issue certain orders with respect to the Company until June 4, 2016. The Company is required under the *Financial Administration Act* (Ontario) and the *Auditor General Act* (Ontario) to provide financial information to the Province for the Province's public reporting purposes.

Recent Legislative Amendments Affecting the Electricity Industry Generally

Tax Incentives

Tax incentives were included in the 2015 Ontario Budget to promote consolidation in the electricity distribution sector. The 2015 Ontario Budget announced a reduction in the tax rate for transfers of electricity assets from 33% to 22% and to NIL for distributors with fewer than 30,000 customers. In addition, the budget also introduced a capital gains exemption where capital gains arise as a result from exiting the payments in lieu of corporate taxes regime. These changes apply for the period beginning January 1, 2016, and ending December 31, 2018.

Ontario Rebate for Electricity Consumers Act, 2016

The Ontario Rebate for Electricity Consumers program commenced on January 1, 2017. This program provides financial assistance to residential, farm, small business and other eligible consumers in respect of electricity costs equal to a rebate of eight percent (8%) of the base invoice amount for each billing period. This rebate appears as a line item on eligible consumers' electricity bills.

Energy Statute Law Amendment Act, 2016

The *Energy Statute Law Amendment Act, 2016* came into force on January 1, 2017. This Act affects the transmission and distribution sector of the electricity industry in Ontario, amending various sections of the Ontario Energy Board Act, the Electricity Act and the *Green Energy Act, 2009* (Ontario). The *Energy Statute Law Amendment Act, 2016* amended the Electricity Act to require the Minister of Energy to produce long-term energy plans that may require the OEB and the IESO to issue implementation plans to achieve the objectives of those plans and the OEB would be guided by such plans' objectives in exercising its powers and performing its duties. The plans may require the IESO to enter into contracts to procure or develop, among other things, transmission systems or any part of such systems. Once the IESO has commenced the procurement process, the OEB is prohibited from granting leave to construct except where the applicant is the party with whom the IESO has entered into a contract for the development or construction of the transmission project. The *Energy Statute Law Amendment Act, 2016* also prohibits new feed-in tariff programs, but grandfathers existing ones.

Climate Change Mitigation and Low-carbon Economy Act, 2016

Pursuant to the *Climate Change Mitigation and Low-carbon Economy Act*, *2016*, the Province introduced a cap and trade program in Ontario beginning January 1, 2017. The program caps the amount of greenhouse gas emissions that Ontario homes and businesses are allowed to emit, and lowers that limit over time. Hydro One Networks Inc., an indirect wholly-owned subsidiary of Hydro One Limited, is deemed a mandatory participant in the cap and trade program based on its annual carbon dioxide equivalent emissions. As required, Hydro One Networks Inc. registered under the program in November 2016, and will comply with its requirements.

Bill 27 – Burden Reduction Act, 2016

Bill 27 was introduced into the Legislative Assembly of Ontario in September 2016 and received Royal Assent on March 22, 2017. This is an omnibus bill amending various statutes, including the Ontario Energy Board Act and the Electricity Act. Bill 27, among other things, amends the Ontario Energy Board Act in a number of ways related to deferral and variance account review and oversight and review of transactions between transmitters and distributors and electricity generators.

Bill 95 – An Act to amend the Ontario Energy Board Act, 1998

Bill 95 was introduced into the Legislative Assembly of Ontario and received Royal Assent on February 22, 2017. Bill 95 impacts a distributor's ability to disconnect customers by broadening the power of the OEB to prescribe, as a condition of a distributor's licence, periods during which disconnections of low-volume consumers may not take place. At the end of February 2017, the OEB issued a decision and order amending the licenses of all Ontario electricity distributors prohibiting the disconnection of residential customers by reason of non-payment for the balance of the 2017 winter period. See "General Development of the Business – Customer Focus – Winter Moratorium and Winter Relief Program" for more information.

RATE-REGULATED UTILITIES

Rate Applications in Ontario

Framework

The term "rate-regulated" is used to refer to an electricity business whose rates for transmission, distribution or other services are subject to approval by a regulator. The rate base of a rate-regulated utility refers to the net book value of the utility's assets for regulatory purposes. Rate base differs from a utility's total assets for accounting purposes, primarily because it includes the regulated assets of a utility. The OEB is the regulator that approves electricity transmission and distribution rates in Ontario. Transmission rates have historically been determined based on a cost-of-service model, while distribution rates are generally determined using a performance-based model. These models are reviewed and modified by the OEB from time to time.

In February 2016, the OEB updated the filing requirements for electricity transmission applications and introduced new revenue requirement setting options. The requirements changed the framework for setting a transmitter's revenue requirement from a cost-of-service approach to a performance-based approach similar to that outlined in the RRF for electricity distributors. To facilitate the transition to the new framework, existing transmitters may still apply for revenue requirement approval based on a one or two year cost-of-service application for their first application following the issuance of the new filing requirements.

In a cost-of-service model, a utility charges rates for its services that allow it to recover the costs of providing its services and earn an allowed return on equity. A utility's return on equity or "ROE" is the rate of return that a regulator allows the utility to earn on the equity portion of the utility's rate base. The costs of providing its services must be prudently incurred. Cost savings are typically passed on to customers in the form of lower rates reflected in future rate decisions. In a cost-of-service model, the utility has the potential to retain cost savings that are achieved in the intervening years between rate decisions.

Cost of Service ($)	+	Return on Equity ($)	=	Revenue Requirement ($)

In a performance-based model, a utility also charges rates for its services that allow it to recover the costs of providing its services and earn an allowed return on equity. However, the rates charged by the utility in a performance-based model assume that the utility becomes increasingly efficient over time, resulting in lower costs to provide the same service. If a utility achieves cost savings in excess of those established by the regulator, the utility may retain some or all of the benefits of those cost savings, which may permit the utility to earn more than its allowed return on equity.

CORPORATE STRUCTURE

Incorporation and Office

Hydro One Limited was incorporated on August 31, 2015, under the OBCA. Its registered office and head office is located at 483 Bay Street, 8th Floor, South Tower, Toronto, Ontario M5G 2P5.

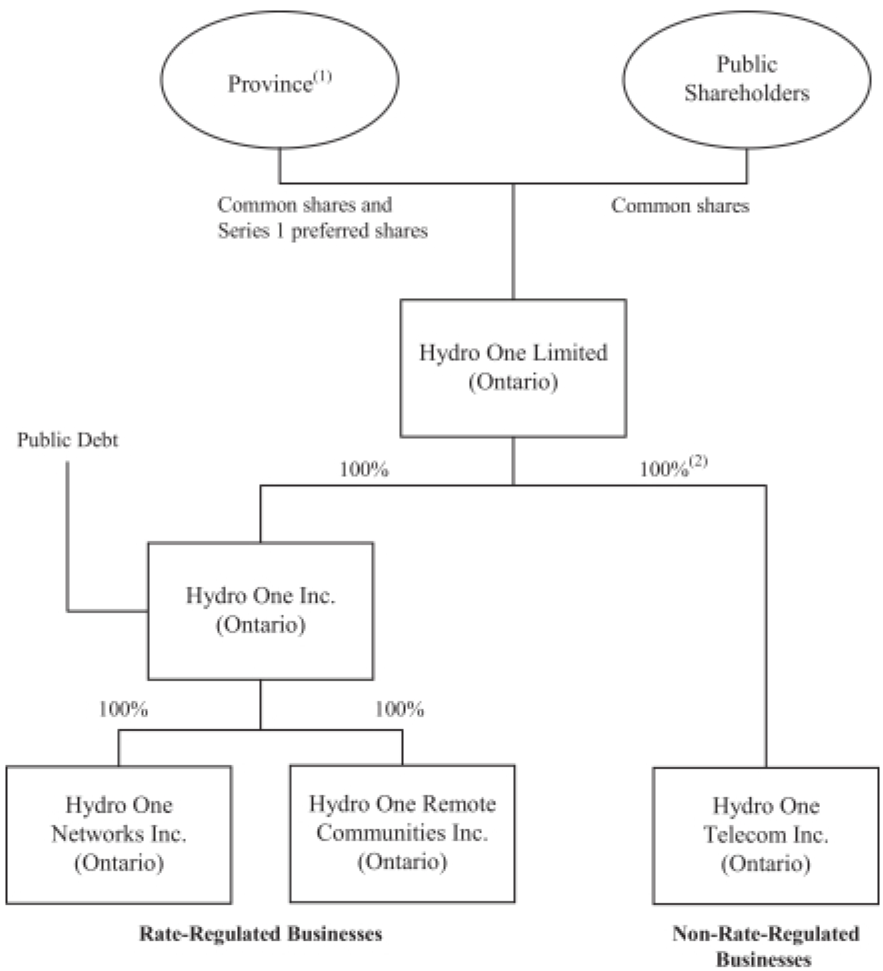
On October 30, 2015, the articles of Hydro One Limited were amended to authorize the creation of an unlimited number of Series 1 preferred shares and an unlimited number of Series 2 preferred shares, with the Series 1 preferred shares to be issued to the Province.

On October 31, 2015, all of the issued and outstanding shares of Hydro One Inc. were acquired by Hydro One Limited from the Province in exchange for the issuance to the Province of common shares and Series 1 preferred shares of Hydro One Limited.

On November 4, 2015, the articles of Hydro One Limited were amended to authorize the consolidation of its outstanding common shares such that 595,000,000 common shares of Hydro One Limited were issued and outstanding.

Corporate Structure and Subsidiaries

The following is a simplified chart showing the organizational structure of Hydro One and the name and jurisdiction of incorporation of certain of its subsidiaries. This chart does not include all legal entities within Hydro One's organizational structure. Hydro One Limited owns, directly or indirectly, 100% of the voting securities of all of the subsidiaries listed below.



Notes:

(1) As of December 31, 2016, the Province directly owned approximately 70.1% of Hydro One Limited's outstanding common shares and 100% of the outstanding Series 1 preferred shares.

(2) Indirectly held through a wholly-owned subsidiary of Hydro One Limited that acts as a holding company for Hydro One's non-rate-regulated businesses.

Certain of Hydro One's subsidiaries are described below:

- **Hydro One Inc**. – acts as a holding company for Hydro One's rate-regulated businesses. Its publicly-issued debt continues to be outstanding.

- **Hydro One Networks Inc**. – the principal operating subsidiary that carries on Hydro One's rate-regulated transmission and distribution businesses.

- **Hydro One Remote Communities Inc.** – generates and supplies electricity to remote communities in northern Ontario.

- **Hydro One Telecom Inc**. – carries on Hydro One's non-rate-regulated telecommunications business.

GENERAL DEVELOPMENT OF THE BUSINESS

The following key events occurred in 2015, 2016 and early 2017 in respect of Hydro One.

Incorporation and Initial Public Offering

On August 31, 2015, Hydro One Limited was incorporated by the Province as its sole shareholder.

On November 5, 2015, Hydro One Limited completed its initial public offering on the TSX by way of a secondary offering of 81,100,000 common shares by the Province at a price of $20.50 per share for aggregate gross proceeds to the Province of $1,662,550,000. On November 12, 2015, the underwriters in the initial public offering exercised their option to purchase an additional 8,150,000 common shares from the Province at a price of $20.50 per share for additional aggregate gross proceeds to the Province of $167,075,000. Hydro One Limited did not receive any proceeds from the initial public offering.

Acquisition of Hydro One Inc.

Prior to the closing of the initial public offering, all of the issued and outstanding common shares of Hydro One Inc. were acquired by Hydro One Limited. Under applicable Canadian securities laws, the acquisition of all of the issued and outstanding shares of Hydro One Inc. was considered a "significant acquisition". Hydro One Limited filed a business acquisition report in respect of the acquisition on January 14, 2016. See "Business of Hydro One – Reorganizations" for more information.

Hydro One Brampton Networks Inc.

On August 31, 2015, all of the issued and outstanding shares of Hydro One Brampton Networks Inc. were transferred to the Province. Hydro One was not a participant in nor did it receive any proceeds from the transfer of Hydro One Brampton Networks Inc. to the Province.

Following the transfer to the Province, Hydro One provided certain management, administrative and smart meter network services to Hydro One Brampton Networks Inc. pursuant to service level agreements. These agreements terminated as of February 28, 2017.

Secondary Common Share Offering

On April 14, 2016, the Province completed a secondary offering of 72,434,800 common shares of Hydro One Limited at a price of $23.65 per share for aggregate gross proceeds to the Province of $1,713,083,020. On April 29, 2016, the underwriters in the secondary offering exercised their option to purchase an additional 10,865,200 common shares from the Province at a price of $23.65 per share for additional aggregate gross proceeds to the Province of $256,961,980. Following the completion of the transaction, the Province held approximately 70.1% of total issued and outstanding common shares. Hydro One Limited did not receive any proceeds from the sale of the common shares by the Province.

First Nations and Hydro One Limited Shares

In July 2016, the Province and First Nations in Ontario, as represented by the Chiefs-in-Assembly, announced an agreement-in-principle for the Province to sell to First Nations up to approximately 15 million shares of Hydro One Limited, depending on the level of First Nation participation. All First Nations have been invited to participate. A minimum threshold of 80% First Nation participation by the end of 2017 is required for this transaction to close. Hydro One Limited is not a party to this transaction.

Agreement to Acquire Orillia Power

In August 2016, the Company reached an agreement to acquire Orillia Power, an electricity distribution company located in Simcoe County, Ontario, for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments. The acquisition is subject to regulatory approval by the OEB.

Acquisition of Great Lakes Power

On October 31, 2016, following receipt of regulatory approval of the transaction by the OEB, Hydro One completed the acquisition of Great Lakes Power, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario. The total purchase price for Great Lakes Power was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. On January 16, 2017, Great Lakes Power's name was changed to Hydro One Sault Ste. Marie LP.

Integration of Haldimand Hydro and Woodstock Hydro

In 2015, the Company acquired Haldimand Hydro and Woodstock Hydro, two Ontario-based local distribution companies. In September 2016, the Company successfully completed the integration of both entities, including the integration of employees, customer and billing information, business processes, and operations.

Acquisitions Generally

The Company intends to continue to evaluate local distribution company consolidation opportunities in Ontario and intends to pursue those acquisitions which deliver value to the Company and its shareholders. Over time, the Company may also consider larger-scale acquisition opportunities or other strategic initiatives outside of Ontario to diversify its asset base and leverage its strong operational expertise. These acquisition opportunities may include other providers of electrical transmission, distribution and other similar services in Canada and in the United States.

Customer Focus

Hydro One is transitioning into a corporation which is more commercially oriented; that is, one that has a greater focus on customers, greater corporate accountability for performance outcomes, and company-wide increase in productivity and efficiency.

Customer Service

Hydro One is committed to delivering significant value to customers by becoming easier to do business with, being available when customers need assistance, and always staying connected. This includes specific, measurable commitments to customers that encompass all areas of service. Hydro One's billing system is stable and outperforming its previous system in terms of timeliness, accuracy and reliability. In 2017, the Company intends to launch a new corporate website, improve its self-service portal, and introduce a newly designed customer bill. Additionally, the Company is committed to increasing the availability of customer service at the local level, and increasing face to face customer engagement.

Review of Operations

Hydro One has been focused on the identification of opportunities for improved corporate performance and the development of strategies to drive more efficient, cost-effective operations. Hydro One conducts regular reviews of key corporate activities and programs, covering areas such as construction services and project management practices, asset deployment and controls, information technology and cybersecurity, vegetation management practices, fleet services and utilization, supply chain management and business continuity planning. Operational improvements in capital planning and execution have already been observed, and improvements have been made to work execution process. The OEB's rate decisions also contain directions to Hydro One to become more cost efficient and improve value to customers.

Winter Moratorium and Winter Relief Program

Hydro One has an existing policy (the winter disconnection moratorium) that from December 1 to March 31 it will not disconnect residential customers whose accounts are in arrears. In 2016, Hydro One instituted its winter disconnection moratorium as of November 25.

Hydro One announced its new Winter Relief Program in December 2016, as an extension of its existing winter disconnection moratorium. This new initiative is intended to help residential customers facing extreme hardship and who have had their electricity service disconnected by reaching out to these customers directly to help re-connect their electricity service for the remainder of the winter. As part of the program, Hydro One will waive reconnection fees and also work with customers to determine payment options to bring their accounts up-to-date and to evaluate various support programs in which certain customers may be eligible to participate.

Ontario Rebate for Electricity Consumers Program

See "The Electricity Industry in Ontario – Recent Legislative Amendments Affecting the Electricity Industry Generally – *Ontario Rebate for Electricity Consumers Act, 2016"* for information on the Ontario Rebate for Electricity Consumers program.

Ombudsman

The Electricity Act requires that the Company have an ombudsman to act as a liaison with customers and to establish procedures for the ombudsman to inquire into and report to the Board on matters raised with the ombudsman by or on behalf of customers. These procedures are set out in a written mandate and terms of reference.

The role of the ombudsman is to facilitate resolution of complaints by customers of the Company that remain unresolved after having been processed through the Company's complaints handling process. The ombudsman is an impartial and independent investigator, who makes recommendations to facilitate the resolution of both individual and systemic issues with a view to achieving a resolution that is fair to both the customer and the Company. The main purposes of the ombudsman are to address procedural and substantive unfairness, handle unresolved complaints, conduct systemic reviews that will lead to improvements in programs and systems, support the Company in holding its employees accountable for carrying out the Company's directives and their responsibilities, and support the Board in its mandate to govern in a just, fair, and equitable manner. The ombudsman also works with the OEB to maintain integrated procedures for liaising with the Company and inquiring into matters raised by customers with the ombudsman. The ombudsman is an office of last resort within the Company.

BUSINESS OF HYDRO ONE

Business Segments

Through its wholly-owned subsidiary Hydro One Inc., Hydro One is Ontario's largest electricity transmission and distribution utility with approximately $25.3 billion in assets and 2016 revenues of over $6.5 billion. Hydro One owns and operates substantially all of Ontario's electricity transmission network and is the largest electricity distributor in Ontario by number of customers. The Company's regulated transmission and distribution operations are owned by Hydro One Inc., a wholly-owned subsidiary of Hydro One Limited. Hydro One delivers electricity safely and reliably to over 1.3 million customers across the province of Ontario, and to large industrial customers and municipal utilities. Hydro One Inc. owns and operates over 30,000 circuit kilometres of high-voltage transmission lines and approximately 123,000 circuit kilometres of primary low-voltage distribution lines.

Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business. Each of the three segments is described below.

Hydro One's transmission and distribution businesses are both operated primarily through Hydro One Networks Inc. This allows both businesses to utilize common operating platforms, technology, work processes, equipment and field staff and thereby take advantage of operating efficiencies and synergies. For regulatory purposes, Hydro One Networks Inc. files separate rate applications with the OEB for each of its licensed transmission and distribution businesses.

Transmission Business

Overview

Hydro One's transmission business consists of owning, operating and maintaining Hydro One's transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on revenue approved by the OEB. All of the Company's transmission business is carried out by its wholly-owned subsidiary Hydro One Inc., through its wholly-owned subsidiary Hydro One Networks Inc. and through other wholly-owned subsidiaries of Hydro One Inc. that own and control Great Lakes Power (now Hydro One Sault Ste. Marie LP), as well as through the Company's 66% interest in B2M Limited Partnership. B2M Limited Partnership is a limited partnership between Hydro One and the Saugeen Ojibway Nation, which owns the transmission line assets relating to two circuits between Bruce TS and Milton TS. Hydro One's transmission business represented approximately 51% of its total assets as at December 31, 2016, and accounted for approximately 51% of its total revenue in 2016, net of purchased power and 50% of its total revenue in 2015, net of purchased power.

The Company's transmission business is one of the largest in North America and is a rate-regulated business that earns revenues mainly from charging transmission rates that are subject to approval by the OEB. In February 2016, the OEB updated the filing requirements for electricity transmission applications and introduced new revenue requirement setting options. During the transition period from the cost-of-service model to the performance-based model, the Company's transmission rates are determined based on a cost-of-service model. Transmission rates are collected by the IESO and are remitted by the IESO to Hydro One on a monthly basis, which means that Hydro One's transmission business has no direct exposure to end-customer counterparty risk.

Transmission rates are based on monthly peak electricity demand across Hydro One's transmission network. This gives rise to seasonal variations in Hydro One's transmission revenues, which are generally higher in the summer and winter due to increased demand, and lower during other periods of reduced demand. Hydro One's transmission revenues also include revenues associated with exporting energy to markets outside of Ontario. Ancillary revenue includes revenues from providing maintenance services to generators and from third party land use.

Business

The Company's transmission system serves substantially all of Ontario, with the exception of the James Bay and Fort Erie areas, and transported approximately 137 TWh of energy throughout the province in 2016. Hydro One's transmission customers consist of 44 local distribution companies (including Hydro One's own distribution business) and 87 large industrial customers connected directly to the transmission network, including automotive, manufacturing, chemical and natural resources businesses. Electricity delivered over the Company's transmission network is supplied by 126 generators in Ontario and electricity imported into the province through interties. Interties are transmission interconnections between neighbouring electric systems that allow power to be imported and exported.

The high voltage power lines in Hydro One's transmission network are categorized as either lines which form part of the "bulk electricity system" or "area supply lines". Power lines which form part of the bulk electricity system typically connect major generation facilities with transmission stations and often cover long distances, while area supply lines serve a local region. Ontario's transmission system is connected to the transmission systems of Manitoba, Michigan, Minnesota, New York and Quebec through the use of interties, allowing for the import and export of electricity to and from Ontario.

Hydro One's transmission assets were approximately $13 billion as at December 31, 2016 and include transmission stations, transmission lines, a control centre and telecommunications facilities. Hydro One has approximately 306 in-service transmission stations and over 30,000 circuit kilometres of high voltage lines whose major components include cables, conductors and wood or steel support structures. All of these lines are overhead power lines except for approximately 277 circuit kilometres of underground cables located in certain urban areas.

B2M Limited Partnership is Hydro One's partnership with the Saugeen Ojibway Nation with respect to the Bruce-to-Milton transmission line. B2M Limited Partnership owns the transmission line assets relating to two circuits between Bruce TS and Milton TS, while Hydro One owns the transmission stations where the lines terminate. Hydro One maintains and operates the Bruce-to-Milton line. Hydro One has a 66% economic interest in the partnership.

Hydro One's transmission network is managed from a central location. This centre monitors and controls the Company's entire transmission network, and has the capability to remotely monitor and operate transmission equipment, respond to alarms and contingencies and restore and reroute interrupted power. There is also a backup facility which would be staffed in the event of an evacuation of the centre.

Hydro One uses telecommunications systems for the protection and operation of its transmission and distribution networks. These systems are subject to very stringent reliability and security requirements, which help the Company meet its reliability obligations and facilitate the restoration of power following service interruptions.

On October 31, 2016, following receipt of regulatory approval of the transaction by the OEB, Hydro One completed the acquisition of Great Lakes Power, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario. The total purchase price for Great Lakes Power was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. On January 16, 2017, Great Lakes Power's name was changed to Hydro One Sault Ste. Marie LP.

See "General Development of the Business – Acquisitions Generally" for more information.

Regulation

Transmission Rate Setting

As discussed under "Rate-Regulated Utilities", transmission rate setting in Ontario has changed. The OEB has created two new revenue plan options: the Custom Incentive Rate Setting Plan (the "Custom IR Method") and the Incentive Index Rate Setting Plan (the "Revenue Cap Index"). Transmitters may still apply for revenue requirement approval based on a one or two year cost-of-service application for their first application following the issuance of the filing requirements, as the OEB has recognized that a transition period may be needed.

Under the Custom IR Method, the revenue requirement is adjusted though the rate term to reflect forecasts, the OEB's inflation analysis, and internal and external benchmarking evidence.

Under the Revenue Cap Index the first year's revenue requirement reflects the transmitter's cost of service, and annually thereafter, this amount is subject to a formulaic increase reflecting productivity and stretch commitments proposed by the transmitter. Revenue Cap Index applicants can request incremental capital funding.

The OEB sets transmission rates based on a two-step process. First, all transmitters apply to the OEB for the approval of their revenue requirements. Second, the OEB aggregates the total revenue requirements of all transmitters in Ontario and applies a formula to arrive at a single set of rates that are charged to ratepayers for the three types of transmission services applicable in Ontario, namely: network services, line connection services and transformation connection services. The three separate rates charged for these services are the same for all transmitters and are referred to as "uniform transmission rates". Uniform transmission rates for all transmitters are set by the OEB on an annual basis, using the revenue requirements set out in the most recent rate decision issued for each transmitter.

The updated filing requirements for transmitters mandate that steps be made towards the integration of core RRF concepts into revenue requirement applications. Transmitters applying for revenue requirements under the Custom IR Method or Revenue Cap Index must include (i) evidence of the continuous improvement and efficiency gains anticipated to be achieved over the rate term; (ii) a mechanism to protect ratepayers in the event of earnings significantly in excess of the regulatory net income supported by the return on equity established in the approved revenue requirement; and (iii) proposed performance metrics applicable to their individual circumstances. A key component of rate–setting under the RRF is benchmarking evidence to support cost forecasts and system planning proposals.

A transmitter must apply for the approval of its revenue requirement for an initial base year covered by the rate decision. The revenue requirement for subsequent years is determined based on a formula that accounts for inflation and certain productivity factors set by the regulator. The revenue requirement in these subsequent years is set on the assumption that the transmitter is lowering its cost of service over the period covered by the rate decision due to efficiency or productivity improvements. A transmitter is permitted to retain all or a portion of the cost savings achieved in excess of the estimate established by the regulator during the period covered by the rate decision.

Recent Transmission Rate Applications

Hydro One Networks Inc., B2M Limited Partnership and Great Lakes Power (now Hydro One Sault Ste. Marie LP) file separate applications for the approval of their revenue requirements for transmission services.

In January 2015, the OEB approved Hydro One Networks Inc.'s 2015 transmission rate order for transmission services, which provided for a revenue requirement of $1,477 million for 2015 and $1,516 million for 2016 (excluding B2M Limited Partnership). These revenue requirements reflect an approved rate base of $9,651 million, return on equity of 9.30% and deemed capital structure of 60% debt and 40% equity. In January 2016, the OEB issued its decision and order on 2016 transmission revenue requirement for Hydro One Networks Inc. approving a revenue requirement of approximately $1,480 million based on an approved rate base of $10,040 million and a return on equity of 9.19%.

In May 2016, Hydro One Networks Inc. filed a transmission rate application with the OEB for its 2017-2018 revenue requirements on a cost of service basis, electing to take advantage of the transition period available to transmitters before the OEB requires transmitters to choose between the two incentive-based revenue plan options. In its application, Hydro One Networks Inc. requested the OEB's approval of rates revenue requirements of $1,505 million for 2017 and $1,586 million for 2018. These rates revenue requirements reflect the requested rate base of $10,554 million for 2017 and $11,226 million for 2018, and reflect an allowed ROE of 9.19% for each year.

In December 2016, pursuant to the OEB's publication of its cost of capital parameters for 2017 rate year, Hydro One Networks Inc. updated its transmission rate application to reflect the change. The revised rates revenue requirement for 2017 is $1,487 million and $1,558 million for 2018. Furthermore, the cost of capital update reflects ROE, short-term and long-term debt cost updates. As a result, the ROE in the application has been updated to 8.78% for 2017 and the same rate is being a placeholder for 2018.

In preparing its application, Hydro One Networks Inc. carried out customer engagement and incorporated the feedback into its application. As part of the transmission rate application, Hydro One Networks Inc. also filed its proposed five-year transmission system capital plan.

In March 2015, B2M Limited Partnership filed an application for revenue requirements covering the 2015 to 2019 period. B2M Limited Partnership requested revenue requirements of $39 million for 2015, $36 million for 2016, $37 million for 2017, $38 million for 2018 and $37 million for 2019. In January 2016, the B2M Limited Partnership revenue requirement was approved. In December 2016, B2M Limited Partnership filed a draft rate order with a revised 2017 revenue requirement of $34 million. See also the Annual MD&A under the subheading "Regulation – B2M LP".

In December 2016, Great Lakes Power filed an application with the OEB for 2017 rates, requesting an increase to the approved 2016 revenue requirement of 1.9%, resulting in an updated revenue requirement of $41 million.

Reliability Standards for Transmission

The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC, both of which are industry organizations involved in promoting and improving the reliability of transmission networks in North America. These reliability standards are enforced by both the IESO and the National Energy Board.

Among its standards, the NERC has also established and continues to issue revised requirements to ensure that utilities and other users, owners and operators of the bulk electricity system in North America have appropriate procedures in place to protect critical infrastructure from cyber-attacks. Hydro One's physical, electronic and information security processes have been and are being upgraded to meet these revised requirements. Hydro One expects to continue to perform additional work and incur further costs to comply with the NERC's updated and revised standards. Hydro One anticipates that these costs will be incurred annually over a number of years and will be recovered in rates. See the Annual MD&A under the subheadings "Risk Management and Risk Factors – Compliance with Laws and Regulations; - Risk Associated with Information Technology Infrastructure and Data Security; - Risks Relating to Asset Condition and Capital Projects" for more information.

Regional Planning

The OEB oversees regional planning processes to ensure that transmission and distribution investments are coordinated at a regional level. The OEB has indicated it will rely on regional planning studies and reports to support rate applications submitted by transmitters and distributors and "leave to construct" applications submitted by transmitters. In Ontario, the regional planning process is led by the transmitter responsible for a particular geographic region. For this purpose, the province is divided into 21 regions. As the largest transmitter in Ontario, Hydro One plays a key role in the regional planning process and is responsible for leading the regional planning process in 20 of the 21 designated regions. The first cycle of the regional planning process for all of the 21 regions is expected to be completed in 2017. Once a transmission and distribution infrastructure plan is finalized, the transmitter responsible for each region will take steps to implement the recommended transmission investments and distributors in the region will implement the recommended distribution investments in their respective service territories.

In conducting regional planning, Hydro One works closely with the IESO and all distributors in the region to jointly identify needs and develop transmission and distribution investment options. Hydro One also coordinates with the IESO on its Integrated Regional Resource Planning process.

Capital Expenditures

The Company anticipates that it will spend approximately $1,086 million to $1,486 million per year, over the next five years, on capital expenditures relating to its transmission business. The Company's capital expenditure plans are included in Hydro One's applications to the OEB for transmission rates. See "Capital Investments – Future Capital Investments" in the Annual MD&A for more information on future capital expenditures.

The Company incurs both sustaining capital expenditures and development capital expenditures. Sustaining capital expenditures are those investments required to replace or refurbish lines or station components to ensure that transmission assets continue to function as originally designed. Hydro One's plans to maintain, refurbish or replace existing assets are based upon risk assessments, asset condition assessments and end-of-service life criteria specific to each type of asset. Priorities are assigned to each type of investment based upon the extent of the risks that it mitigates.

Investments to sustain Hydro One's transmission assets are critical to maintain the safety, reliability and integrity of its existing transmission network. Hydro One's sustainment capital plan is designed to maintain Hydro One's transmission reliability performance, as determined by measures such as the average length (in minutes) of unplanned interruptions per delivery point. The Company expects that significant investments will be required in its existing infrastructure over the long term.

The Company's development capital expenditure plan is designed to address Ontario's changing generation profile, accommodate load growth in areas throughout Ontario and support the expected change in generation mix. Development capital expenditures include those investments required to develop and build new large-scale projects such as new transmission lines and stations and smaller projects such as transmission line or station reinforcements, extensions or additions.

The Company engages with various stakeholders, including its customers, as it develops its capital plans. It also engages affected communities and parties who may be impacted by individual projects. The Company also consults with First Nations and Métis communities whose rights may be affected by its projects.

Competitive Conditions

The Company's operations are currently limited to Ontario, where the Company operates and maintains substantially all of Ontario's transmission system. Competition for transmission services in Ontario is currently limited. The adoption by the OEB of uniform transmission rates that apply to all transmitters also reduces the financial incentive for customers to seek alternative transmission providers, since each transmitter in Ontario charges the same uniform rate for transmission services. Hydro One competes with other transmitters for the opportunity to build new large-scale transmission facilities in Ontario. Management believes that Hydro One is well-positioned to pursue the development of such facilities. However, the competitive process was amended by the proclamation of the *Energy Statute Law Amendment Act, 2016* to allow for the selection of a transmitter outside the existing competitive process. See "The Electricity Industry in Ontario – Recent Legislative Amendments Affecting the Electricity Industry Generally– *Energy Statute Law Amendment Act, 2016*" for more information.

Hydro One does not compete with other transmitters with respect to investments which are made to sustain or develop its existing transmission infrastructure.

Distribution Business

Overview

Hydro One's distribution business consists of owning, operating and maintaining Hydro One's distribution system, which Hydro One, through Hydro One Inc., owns primarily through its wholly-owned subsidiary, Hydro One Networks Inc., the largest local distribution company in Ontario. The Company's distribution system is also the largest in Ontario. The Company's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that are subject to approval by the OEB. The Company's distribution rates are generally determined using a performance-based model, except for the distribution rates of Hydro One Remote Communities Inc., which are set on a cost-recovery basis and do not include a return on equity.

Hydro One's distribution business represented approximately 37% of its total assets as at December 31, 2016, and accounted for approximately 47% of its total revenue in 2016, net of purchased power and 48% of its total revenue in 2015, net of purchased power. Hydro One's distribution business also includes the business of its wholly-owned subsidiary, Hydro One Remote Communities Inc., which supplies electricity to customers in remote communities in northern Ontario. Distribution revenues include distribution rates approved by the OEB and amounts to reimburse Hydro One for the cost of purchasing electricity delivered to its distribution customers. Distribution revenues also include minor ancillary service revenues, such as fees related to the joint use of the Company's distribution poles by participants in the telecommunications and cable television industries, as well as miscellaneous charges such as charges for late payments.

As at December 31, 2016, Hydro One's distribution assets were $9,337 million.

Business

Hydro One delivers electricity through its distribution network to over 1.3 million residential and business customers, most of whom are located in rural areas, as well as 53 local distribution companies (including Hydro One's own distribution business).

Hydro One's distribution system includes approximately 123,000 circuit kilometres of primary low-voltage distribution lines and approximately 1,000 distribution and regulating stations. Other distribution assets include poles, transformers, service centres and equipment.

Hydro One's distribution system services a predominantly rural territory. As a result of the lower population density in the Company's service territory, the Company's costs to provide distribution services may be higher than those of distributors who service urban areas. Furthermore, unlike the distribution systems found in urban areas, most of Hydro One's distribution system was not designed with redundancy, to be interconnected in loops with other distribution lines, with the result that interruptions experienced at any point along a distribution line in Hydro One's network can cause all customers downstream of the interruption point to lose power. Accordingly, the reliability of Hydro One's distribution system is lower than that of local distribution companies which service urban territories that typically have redundancy built into their systems. The Company engages in vegetation management activities to maintain the reliability of Hydro One's distribution system on a preventive basis and to protect public health and safety. This consists of the trimming or removal of trees to lower the risk of contact with distribution lines, thereby reducing the risk of power outages, and preventing potential injury to the public or employees. The Company's monitoring systems assist with determining areas of priority and with system restoration. The Company relies on its local line crews for these restoration activities.

Hydro One's distribution business is involved in the connection of new sources of electricity generation, including renewable energy. Hydro One invests in upgrades and modifications to its distribution system to accommodate these new sources of generation and ensure the continued reliability of its distribution network. As at December 31, 2016, there were approximately 15,000 small, mid-size and large embedded generators connected to Hydro One's distribution network, including approximately 14,000 generators with capacities of up to 10 kW. As at December 31, 2016, Hydro One also had approximately 1,500 generators pending connection.

Hydro One has played a significant role in the installation of smart meters and the migration of distribution customers to time of use pricing in Ontario. Smart meters are regarded as an integral means of promoting a culture of conservation, and they allow customers to change their electricity consumption patterns and reduce their costs. Hydro One has completed all material activities associated with the implementation of smart meters, and has transitioned the vast majority of its customers to time of use pricing.

Acquisitions

<u>Agreement to Acquire Orillia Power</u>

In August 2016, the Company reached an agreement to acquire Orillia Power, an electricity distribution company located in Simcoe County, Ontario, for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments. The acquisition is subject to regulatory approval by the OEB.

<u>Integration of Haldimand Hydro and Woodstock Hydro</u>

In 2015, the Company acquired Haldimand Hydro and Woodstock Hydro, two Ontario-based local distribution companies. In September 2016, the Company successfully completed the integration of both entities, including the integration of employees, customer and billing information, business processes, and operations.

See "General Development of the Business – Acquisitions Generally" for more information.

Regulation

<u>Distribution Rates</u>

Distribution rates in Ontario are determined using a performance-based model set out in the OEB's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, which is sometimes referred to as the "RRF". Under the RRF, distributors in Ontario may choose one of three rate-setting methods, depending on their capital requirements: 4th Generation Incentive Rate-Setting (now known as Price Cap IR), Custom Incentive Rate-Setting, or Annual Incentive Rate-Setting Index.

The RRF contemplates that a distributor will apply for the approval of its revenue requirement for an initial base year covered by the rate decision. The revenue requirement for subsequent years is determined based on a formula that accounts for inflation and certain productivity factors set by the regulator. The revenue requirement in these subsequent years is set on the assumption that the distributor is lowering its cost of service over the period covered by the rate decision due to efficiency or productivity improvements. The RRF allows the distributor to retain all or a portion of the cost savings achieved in excess of the estimate established by the regulator during the period covered by the rate decision. This allows the distributor an ability to earn more than its allowed return on equity. The RRF provides incentives for distributors to achieve certain performance outcomes, namely: customer focus, operational effectiveness, public policy responsiveness and financial performance. The OEB has indicated that customer focused outcomes and continuous performance improvements by distributors are central to the RRF framework objectives. The OEB has further indicated that distributors should develop plans that respond to customer service needs.

A distributor must submit proposed performance measures as part of its application for distribution rates under the RRF. Distributors may also propose their own performance measures for approval by the OEB. In its most recent distribution application, Hydro One submitted eight additional quantitative measures relating to areas that will be the subject of increased spending levels over the next few years, such as pole replacements, distribution station refurbishments and vegetation management. Distributors are required to report to the OEB on their performance against the performance measures approved as part of their most recent rate decision.

The OEB's review process under the RRF follows a process similar to that of a transmission rate application for the review of the anticipated cost of service for providing distribution services, other than as noted above. Once the revenue requirement for distribution services is determined, it is allocated across the distributor's customer rate classes using a methodology approved by the OEB resulting in the setting of individual rates for distribution services based on each customer rate class. Hydro One currently has 13 customer rate classes.

Distribution rates in Ontario are not the same for all distributors and reflect the particular circumstances of each distributor, including its own costs of providing electricity service to its own particular customers. The OEB policy, *A New Distribution Rate Design for Residential Electricity Customers*, changes the current distribution rate design for residential customers (a combination of a fixed monthly rate and a variable charge) to a fixed monthly charge only. In December 2015, the OEB increased the transition period for certain customer classes of Hydro One Networks Inc. to eight years to mitigate bill impacts. Implementation will occur over the next three to seven years for Hydro One Networks Inc.'s residential customers.

The OEB has also initiated a working group to consider possible changes to the design of rates for commercial industrial customers. Changes to rate design will not impact the rates revenue requirement to be collected for each customer class.

Distribution Rate Applications

The Company's distribution rates, other than the distribution rates of Hydro One Remote Communities Inc., are determined using a performance-based model.

In March 2015, the OEB issued a decision regarding Hydro One Networks Inc.'s distribution rates for the three-year period from 2015 to 2017, providing for a revenue requirement of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The 2015 revenue requirement reflects an approved rate base of $6,552 million, return on equity of 9.30% and a deemed capital structure of 60% debt and 40% equity. The rates are effective as of January 1 in each year. On January 14, 2016, the OEB issued its final decision and order approving Hydro One Networks Inc.'s draft rate order for 2016 rates.

In December 2016, the OEB issued its decision and order approving Hydro One Networks Inc.'s distribution rates effective January 1, 2017. The overall impact of this decision is a reduction of the proposed 2017 revenue requirement to approximately $1,415 million from $1,486 million. The 2017 revenue requirement reflects an approved rate base of $7,190 million, return on equity of 8.78% and a deemed capital structure of 60% debt and 40% equity. The overall impact of the new rates is a reduction in distribution delivery charges for most residential customers.

In December 2016, the OEB approved increases to the rates charged in the service areas for the former Haldimand Hydro, Woodstock Hydro and Norfolk Hydro, effective January 2017.

Hydro One Networks Inc. expects to file a distribution rate application for 2018 to 2022 in the first quarter of 2017.

Hydro One Remote Communities Inc.'s business is exempt from a number of sections of the Electricity Act which relate to the competitive market. For example, Hydro One Remote Communities Inc. continues to apply bundled rates to customers in remote communities. Hydro One Remote Communities Inc.'s business is operated on a break-even basis, without a return on equity included in rates. As a result, any net income or loss in the year related to the regulated operations of Hydro One Remote Communities Inc. is recorded in a regulatory variance account for inclusion in the calculation of future customer rates.

For more information, see the Annual MD&A under the heading "Regulation".

Conservation and Demand Management

CDM requirements in Ontario require distributors to achieve specific energy savings targets by encouraging their customers to reduce their energy usage. Distributors seek to achieve these targets through a number of different initiatives, including by offering customers energy saving devices for use at home, cash rebates for the purchase of energy efficient light bulbs and other products. Incentive programs are also offered to small, medium, and large businesses, as well as industrial customers. Distributors are responsible for developing and submitting CDM plans and reporting on their progress towards achieving specific energy-savings targets. The IESO oversees compliance with CDM requirements in Ontario and also reimburses distributors for the costs of complying with CDM requirements. Hydro One expects that its costs of complying with CDM requirements will be fully reimbursed by the IESO. As a result, CDM-related costs that are reimbursed by the IESO are not included in Hydro One's rate applications to the OEB.

Distributors in Ontario are collectively required to achieve a total of 7 TWh of electricity savings by December 31, 2020, with each local distribution company being allocated individual energy-savings targets and budgets.

Targets and budgets for CDM were allocated to distributors in October 2014. Hydro One Networks Inc.'s 2015-2020 CDM energy savings target is 1,159 GWh and its CDM plan was approved by the IESO on July 8, 2015. In December 2016, Hydro One Networks Inc.'s 2015-2020 CDM energy savings target was revised to 1,221 GWh to reflect the integration of the CDM targets of Norfolk Power, Haldimand Hydro and Woodstock Hydro. In December 2016, Hydro One Networks Inc. also submitted a joint CDM plan with another local distribution company to the IESO for approval. The joint target for Hydro One Networks Inc. increased by 35 GWh to 1,256 GWh by 2020.

Capital Expenditures

Hydro One's asset sustainment activities are based on an assessment of asset condition. Distribution asset renewals are undertaken when assessments indicate there is a high risk of failure and where further maintenance activities are not appropriate. Capital expenditures for the Company's distribution business in the near term are anticipated to focus on new load connections, storm damage, wood pole replacement, and system capability reinforcement. In addition, the Company expects to continue to construct new distribution lines and stations in the future in response to system growth forecasts, continued suburban community development, high load relief requirements and requirements to connect new sources of generation. The Company expects that it will spend approximately $647 million to $771 million per year over the next five years on capital expenditures relating to its distribution business.

Hydro One is continuing to modernize its distribution system through the deployment of smart devices (including remotely controllable switches and breakers as well as faulted circuit indicators) as power system assets are renewed. Hydro One is also implementing a new Distribution Management System ("DMS") at its Ontario Grid Control Centre. The DMS will enable distribution components to be monitored and controlled, perform real-time analysis and determine, with greater precision, the location of equipment failures. Additional functionality is planned, in future, to allow field staff to view system conditions remotely in real-time. Smart metering data will also be used to deliver operational and asset management benefits such as better notification of outages and their scope, asset loading information and other data.

For more information on future capital expenditures, see the Annual MD&A under the subheading "Capital Investments – Future Capital Investments".

Competitive Conditions

Hydro One's distribution service area is set out in its licence issued by the OEB. Only one distributor is permitted to provide distribution services in a service territory, and distributors have exclusive rights to provide service to new customers located within their service territory. As a result, there is very little direct competition for distribution services in Ontario, except near the borders of adjoining service territories, where a distributor may apply to the OEB to claim the right to serve new customers who are not currently connected to its distribution grid.

In March 2016, the OEB directed all local distribution companies to eliminate load transfer arrangements by June 21, 2017. Load transfer arrangements arise when a customer is within one distributor's service area but is served by a second distributor. The Company has load transfer arrangements with over 50 local distribution companies. Hydro One Networks Inc. has developed an implementation plan to eliminate load transfer arrangements. As a result, some of the Company's customers will be transferred to the adjacent local distribution companies and other customers will be added to the Company's customer base.

To create more efficiency in the distribution sector, the Premier's Advisory Council on Government Assets endorsed the need for faster consolidation among local distribution companies in Ontario, which may result in competition for acquisition or merger opportunities. Potential acquirers may include strategic and financial buyers, in addition to other local distribution companies.

Other Business

Hydro One's other business segment consists of principally its telecommunications business, which provides telecommunications support for the Company's transmission and distribution businesses as well as certain corporate activities including a deferred tax asset. The telecommunication business is carried out by its wholly-owned subsidiary Hydro One Telecom Inc. It also offers communications and information technology solutions to organizations with broadband network requirements utilizing Hydro One Telecom Inc.'s fibre optic network to provide diverse, secure and highly reliable connectivity.

Hydro One Telecom Inc. is not regulated by the OEB. However, Hydro One Telecom Inc. is registered with the Canadian Radio-television and Telecommunications Commission as a non-dominant, facilities-based carrier, providing broadband telecommunications services in Ontario with connections to Montreal, Quebec, Buffalo, New York and Detroit, Michigan.

The other business segment represented approximately 12% of Hydro One's total assets as at December 31, 2016, and accounted for approximately 2% of its total revenue, net of purchased power in each of 2016 and 2015. The deferred tax asset arose on the transition from the provincial payments in lieu of tax regime to the federal tax regime in connection with the Company's initial public offering and reflects the revaluation of the tax basis of Hydro One's assets to fair market value.

First Nations and Métis Communities

Hydro One believes that building and maintaining respectful, positive and mutually beneficial relationships with First Nations and Métis communities across the province is important to achieving the Company's corporate objectives. Hydro One is committed to working with First Nations and Métis communities in a spirit of cooperation, partnership and shared responsibility. Hydro One's equity partnership with the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line demonstrates the Company's commitment to these principles. In keeping with the Company's First Nations and Métis Relations Policy, Hydro One's First Nations and Métis Relations team provides guidance and advice to support the Company in developing and advancing positive relationships. Hydro One also has several programs related to First Nations and Métis communities and their citizens. These include educational and training opportunities which provide opportunities for work terms, First Nations and Métis procurement partnership agreements along with community investments, customer support and outreach. Together, Hydro One Networks Inc. and Hydro One Remote Communities Inc. serve approximately 90 First Nation communities.

The Company's Health, Safety, Environment and First Nations & Métis Committee of the Board is responsible for assisting the Board in discharging the Board's oversight of responsibilities relating to effective occupational health and safety and environmental policies and practices at Hydro One, and its relationship with First Nations and Métis communities.

Outsourced Services

To gain efficiencies and cost reductions, Hydro One has outsourced certain non-core functions, including facilities management services with respect to its stations and other facilities, and certain back-office services such as information technology, payroll, supply chain, call centre and accounting services. The Company's back-office services and call centre services are provided by a third party service provider under an agreement that expires on December 31, 2019 for back-office services, and on February 28, 2018 for call centre services. The Company has an option to renew the agreement for two additional terms of approximately one year each. The Company's facilities management services are provided by a third party service provider under an agreement that expires on December 31, 2024 with an option for the Company to renew the agreement for an additional term of three years.

Employees

As at December 31, 2016, Hydro One had approximately 5,500 regular employees and over 2,000 non-regular employees province-wide comprised of a mix of skilled trades, engineering, professional, managerial and executive personnel. Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for variable workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to access highly trained and appropriately skilled workers on a project-by-project basis. This provides the Company with more flexibility to address seasonal needs and unanticipated changes to its budgeted work programs. The Company also offers apprenticeship and technical training programs to ensure that future staffing needs will continue to be met.

For more information on employees, see the Annual MD&A under the heading "Hydro One Work Force".

Health, Safety and Environmental Management

Hydro One has an integrated Health, Safety and Environment Management System that includes key elements for the successful minimization of risk and continued performance improvements. Health, safety and environmental hazards and risks are identified and assessed and controls are implemented to mitigate significant risks. The Company has policies in place regarding Health and Safety, Environment, Workplace Violence and Harassment and Public Safety.

Hydro One Networks Inc. is a designated "Sustainable Electricity Company" by the Canadian Electricity Association. The brand demonstrates Hydro One's commitment to responsible environmental, social and economic practices, and to the principles of sustainable development.

Given the nature of the work undertaken by Hydro One employees, health and safety remains one of the Company's top priorities. The Company is committed to creating and maintaining a safe workplace which is one of Hydro One's stated core values, and maintaining safety through a concentrated focus on the elimination of serious incidents or "near-misses" which have the potential to cause serious injuries. The Company has developed and is continuing to develop a number of programs and initiatives for accident prevention and to minimize the risk of injury to the public associated with its facilities and operations.

Measures are in place to monitor, on a regular basis, health, safety and environment performance using proactive and reactive measures and/or qualitative and quantitative measures. Since 2004, the evolution of Hydro One's recordable rate, its key health and safety performance measure, has seen a reduction of approximately 85% in the number of recordable rate incidents. All measures are monitored by management and by the Health, Safety, Environment and First Nations & Métis Committee. Management compensation has been tied, in part, to success in achieving annual health and safety performance targets. A program allowing for an effective early and safe return to work has allowed the Company to ensure that, when injuries occur, employees recover and return to the workplace as soon as possible.

In 2016, Hydro One continued with its "Journey to Zero" safety initiative that began in 2009. This initiative compares Hydro One to other companies to identify performance gaps. Safety perception assessments were completed in 2009, 2013 and 2015. The assessment identified opportunities for improvement and forms the development of new health and safety initiatives using cross-functional teams from across the province.

Environmental Regulation

Hydro One is subject to extensive federal, provincial and municipal regulation relating to the protection of the environment that governs, among other things, environmental assessments, discharges to water and land and the generation, storage, transportation, disposal and release of various hazardous substances. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimated changes are accounted for prospectively.

Permits and Approvals

The Company is required to obtain and maintain specified permits and approvals from federal, provincial and municipal authorities relating to the design, construction and operation of new and upgraded transmission and distribution facilities. Examples include environmental assessment approvals, permits for facilities to be located in parks or other regulated areas, water crossing permits, and approvals to discharge to air and water. Some projects may require environmental approvals from the federal government. Interconnections with neighbouring utilities in other provinces and states also require federal approval and will be subject to federal regulatory review.

In general, larger projects are subject to an individual environmental assessment process, pursuant to the *Environmental Assessment Act* (Ontario). The majority of approvals fall under a class environmental assessment process which provides for more streamlined approvals. The scope, timing and cost of environmental assessments are dependent on the scale and type of project, the location (urban versus rural), the environmental sensitivity of affected lands and the significance of potential environmental effects.

Regulation of Releases

Federal, provincial and municipal environmental legislation regulates the release of specific substances into the environment through the prohibition of discharges that will or may have an adverse effect on the environment, which can include liquids, gasses and noise. Releases occur in the course of the Company's normal operations. Accordingly, Hydro One has spill, leak prevention and leak mitigation programs involving the testing, replacement, repair and installation of containment systems including re-gasketting of transformers and sulphur-hexafluoride-filled equipment. In addition, the Company has an emergency response capability which the Company believes is sufficient to minimize the environmental impact of spills and to comply with its legal obligations.

Pursuant to the *Climate Change Mitigation and Low-carbon Economy Act, 2016*, the Province introduced a cap and trade program in Ontario beginning January 1, 2017. For more information, see "The Electricity Industry in Ontario – Recent Legislative Amendments Affecting the Electricity Industry Generally – *Climate Change Mitigation and Low-carbon Economy Act, 2016*".

Hazardous Substances

Hydro One manages a number of hazardous substances, such as PCBs, herbicides, and wood preservatives. In addition, some facilities have substances present which are designated for special treatment under occupational health and safety legislation, such as asbestos, lead and mercury. The Company has environmental management programs in place to deal with PCBs, herbicides, asbestos, and other hazardous substances.

Land Assessment and Remediation

Hydro One has a pro-active land assessment and remediation program in place to identify and, where necessary, remediate historical contamination that has resulted from past operational practices and uses of certain long-lasting chemicals at the Company's facilities. These programs involve the systematic identification of contamination at or from these facilities and, where necessary, the development of remediation plans for the Company's properties and affected adjacent private properties. As at December 31, 2016, future consolidated expenditures related to Hydro One's land assessment and remediation program were estimated at approximately $61 million, and undiscounted liabilities were estimated at approximately $66 million. These consolidated expenditures are expected to be spent over the period ending 2032. Additional acquisitions could add to land assessment and remediation expenditures. The consolidated expenditures on this program for 2016 were approximately $9 million. These costs are expected to be recovered in the Company's transmission and distribution rates.

Insurance

Hydro One maintains insurance coverage, including liability, all risk property, boiler and machinery and directors' and officers' insurance. The Company also maintains other insurance coverage that is required by law, covering risks such as automobile liability, pesticide liability and aircraft liability. The Company does not have insurance for damage to its transmission and distribution wires, poles or towers located outside transmission and distribution stations, including damage caused by severe weather, other natural disasters or catastrophic events or for environmental remediation costs. The OEB has generally permitted the recovery of costs associated with extreme weather events, such as the ice storm that occurred in 1998.

Reorganizations

In 2015, prior to the closing of the initial public offering of Hydro One Limited, Hydro One completed a series of transactions resulting in, among other things, the acquisition by Hydro One Limited of all of the issued and outstanding shares of Hydro One Inc. and the issuance of new common shares and preferred shares of Hydro One Limited to the Province. The Province then sold a portion of its common shares of Hydro One Limited pursuant to the initial public offering. A series of pre-closing steps occurred, including:

- On October 31, 2015, Hydro One Inc. repurchased its existing preferred shares held by the Province for cancellation at a price equal to the redemption price of the preferred shares (being equal to approximately $323 million) satisfied by the issuance to the Province of common shares of Hydro One Inc. having an aggregate fair market value equal to the price to be paid for the preferred shares.

- All of the issued and outstanding common shares of Hydro One Inc. were acquired by Hydro One Limited in return for the issuance to the Province of 12,197,500,000 common shares and 16,720,000 Series 1 preferred shares of Hydro One Limited.

- Hydro One Inc. and certain of its subsidiaries were required to pay a $2.6 billion "departure tax" to the Ontario Electricity Financial Corporation as a consequence of the initial public offering.

- The outstanding common shares of Hydro One Limited were consolidated such that 595,000,000 common shares were issued and outstanding immediately prior to the closing of the initial public offering.

Under applicable Canadian securities laws, the acquisition of all of the issued and outstanding shares of Hydro One Inc. was considered a "significant acquisition". Hydro One Limited filed a business acquisition report in respect of the acquisition on January 14, 2016. See also "General Development of the Business" for more information.

RISK FACTORS

A discussion of Hydro One Limited's risk factors can be found under the heading "Risk Management and Risk Factors" in the Annual MD&A.

DIVIDENDS

The Company did not declare or pay cash dividends in 2015. In 2016, the Company declared and paid cash dividends to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Common Share
February 11, 2016	March 17, 2016	March 31, 2016	$0.34[1]
May 5, 2016	June 14, 2016	June 30, 2016	$0.21
August 11, 2016	September 14, 2016	September 30, 2016	$0.21
November 10, 2016	December 14, 2016	December 30, 2016	$0.21

[1] This was the first common share dividend declared by the Company following the completion of its initial public offering in November 2015. The $0.34 per share dividend included $0.13 for the post-IPO period from November 5 to December 31, 2015, and $0.21 for the quarter ended March 31, 2016.

On February 9, 2017, the Board declared a dividend of $0.21 per share on each of its outstanding common shares to be paid on March 31, 2017 to shareholders of record on March 14, 2017. The dividend represents payment for the first quarter ending March 31, 2017.

In 2016, the Company declared and paid cash dividends to the Province, the sole holder of the Series 1 preferred shares as follows:

Date Declared	Record Date	Payment Date	Amount per Preferred Share
February 11, 2016	N/A	February 22, 2016	$0.32602739
May 5, 2016	N/A	May 20, 2016	$0.265625
August 11, 2016	N/A	August 22, 2016	$0.265625
November 10, 2016	N/A	November 21, 2016	$0.265625

On February 9, 2017, the Board declared a dividend of $0.265625 per share on each of its Series 1 preferred shares and it was paid on February 21, 2017.

Dividend Policy

The Board has established a dividend policy pursuant to which Hydro One Limited expects to pay an annualised dividend amount on its common shares, based on a target payout ratio of 70% to 80% of net income. The amount and timing of any dividends payable by Hydro One Limited will be at the discretion of the Board and will be established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board may consider relevant.

The preferred shares of Hydro One Limited are entitled to a preference over the common shares with respect to the payment of dividends. Other than the foregoing, there is currently no restriction that would prevent the Company from paying dividends at current levels.

For more information on dividends, see the notes to the audited consolidated financial statements of Hydro One Limited as at and for the years ended December 31, 2016 and 2015 under the headings "Dividends" and "Subsequent Events".

Dividend Reinvestment Plan

On February 11, 2016, the Board approved the creation of a Dividend Reinvestment Plan which is currently in place. The Dividend Reinvestment Plan enables eligible shareholders to have their regular quarterly cash dividends automatically reinvested in additional Hydro One common shares acquired on the open market.

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

The following description may not be complete and is subject to, and qualified in its entirety by reference to, the terms and provisions of Hydro One Limited's articles, as they may be amended from time to time.

Hydro One Limited's authorized share capital consists of an unlimited number of common shares and an unlimited number of preferred shares, issuable in series. As at December 31, 2016, there were 595,000,000 common shares, 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Common Shares

Holders of common shares are entitled to receive notice of and to attend all meetings of shareholders, except meetings at which only the holders of another class or series of shares are entitled to vote separately as a class or series, and holders of common shares are entitled to one vote per share at all such meetings of shareholders. Hydro One Limited's common shares are not redeemable or retractable. Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares, including the Series 1 preferred shares and Series 2 preferred shares, holders of common shares are entitled to receive dividends if, as, and when declared by the Board. Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares, including the Series 1 preferred shares and Series 2 preferred shares, holders of common shares are also entitled to receive the remaining assets of Hydro One Limited upon its liquidation, dissolution or winding-up or other distribution of Hydro One Limited's assets for the purposes of winding-up its affairs. See "Dividends – Dividend Policy" for a description of Hydro One Limited's dividend policy.

The Voting Securities of Hydro One Limited, which include the common shares, are subject to share ownership restrictions under the Electricity Act and certain other provisions contained in the articles of Hydro One Limited related to the enforcement of those share ownership restrictions. The share ownership restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert), other than the Province or an underwriter who holds Voting Securities solely for the purposes of distributing them to purchasers who comply with the share ownership restrictions, may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities of Hydro One Limited.

Preferred Shares

Hydro One Limited may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Board is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of preferred shares.

Subject to the OBCA, holders of Hydro One Limited's preferred shares or a series thereof are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One Limited except that votes may be granted to a series of preferred shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of preferred shares ranks on parity with every other series of preferred shares with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One Limited. The preferred shares are entitled to a preference over the common shares and any other shares ranking junior to the preferred shares with respect to payment of dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One Limited.

Series 1 Preferred Shares and Series 2 Preferred Shares

For the period commencing from October 31, 2015, and ending on and including November 19, 2020, the holders of Series 1 preferred shares will be entitled to receive fixed cumulative preferential dividends of \$1.0625 per share per year, if and when declared by the Board, payable quarterly on the 20th day of November, February, May and August in each year. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 preferred shares will not be redeemable by Hydro One Limited prior to November 20, 2020, but will be redeemable by Hydro One Limited on November 20, 2020 and on November 20 every fifth year thereafter at a redemption price equal to \$25.00 for each Series 1 preferred share redeemed, plus any accrued or unpaid dividends. The holders of Series 1 preferred shares will have the right, at their option, on November 20, 2020 and on November 20 every fifth year thereafter, to convert all or any of their Series 1 preferred shares into Series 2 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 preferred shares will be redeemable by Hydro One Limited at a redemption price equal to $25.00 for each Series 2 preferred share redeemed if redeemed on November 20, 2025, or on November 20 every fifth year thereafter or $25.50 for each Series 2 preferred share redeemed if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 preferred shares will have the right, at their option, on November 20, 2025, and on November 20 every fifth year thereafter, to convert all or any of their Series 2 preferred shares into Series 1 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

In the event of the liquidation, dissolution or winding-up of Hydro One Limited, or any other distribution of assets of Hydro One Limited for the purpose of winding-up its affairs, the holders of Series 1 preferred shares and Series 2 preferred shares will be entitled to receive $25.00 for each Series 1 preferred share and each Series 2 preferred share held by them, plus any unpaid dividends, before any amounts are paid or any assets of Hydro One Limited are distributed to holders of common shares and any shares ranking junior to the Series 1 preferred shares and Series 2 preferred shares. After payment of those amounts, the holders of Series 1 preferred shares and Series 2 preferred shares will not be entitled to share in any further distribution of the property or assets of Hydro One Limited.

Except as required by the OBCA, neither the holders of Series 1 preferred shares nor the holders of Series 2 preferred shares shall be entitled to receive notice of, or to attend meetings of shareholders of Hydro One Limited and shall not be entitled to vote at any such meeting, unless Hydro One Limited fails for eight quarters, whether or not consecutive, to pay in full the dividends payable on the Series 1 preferred shares or Series 2 preferred shares, as applicable, whereupon the holders of Series 1 preferred shares and Series 2 preferred shares, as applicable, shall become entitled to receive notice of and attend all meetings of shareholders, except class meetings of any other class of shares, and shall have one vote for each Series 1 preferred share or Series 2 preferred share held at such meetings, as applicable.

CREDIT RATINGS

For a description of Hydro One Limited's credit ratings, see the Annual MD&A under the heading "Liquidity and Financing Strategy".

MARKET FOR SECURITIES

Trading Price and Volume

The common shares are listed on the TSX under the symbol "H". The following table sets forth the high and low reported trading prices and the trading volume of the common shares on the TSX for each month commencing January 2016:

Period	High ($)	Low ($)	Volume
January 2016 ……………………………………………	22.60	21.85	3,929,776
February 2016 …………………………………………….	23.31	21.90	4,489,699
March 2016 …..……………………………………………	24.50	23.15	7,835,876
April 2016………………………………………………….	24.50	23.50	21,127,653
May 2016………………………………………………	24.84	23.56	23,222,353
June 2016…………………………………………………..	25.98	24.14	30,645,553

Period	High ($)	Low ($)	Volume
July 2016……………………………………………	26.80	25.51	8,548,768
August 2016…………………………………………..	26.48	25.10	7,138,631
September 2016………………………………………	26.54	25.36	7,031,417
October 2016…………………………………………	26.02	24.02	6,765,511
November 2016 ………………………………………	24.58	22.06	11,932,522
December 2016……………………………………….	23.65	22.59	9,719,103
January 2017…………………………………………	24.49	23.49	8,368,116
February 2017………………………………………..	24.17	23.22	8,400,000
March 1 to March 24 2017………………………….	24.08	23.04	8,400,000

The Series 1 preferred shares and Series 2 preferred shares of Hydro One Limited are not listed or quoted on any marketplace.

DIRECTORS AND OFFICERS

Directors and Executive Officers

The following table sets forth information regarding the directors and executive officers of Hydro One as of December 31, 2016. Each of the directors was first appointed on August 31, 2015. Each director is elected annually to serve for one year or until his or her successor is elected or appointed.

Name, Province or State and Country of Residence	Age	Position/Title	Independent	Principal Occupation	Committees
Mayo Schmidt Ontario, Canada	59	President and Chief Executive Officer and Director	No	President and Chief Executive Officer	—
Paul Barry North Carolina, United States	59	Executive Vice President, Strategy and Corporate Development		Executive Vice President, Strategy and Corporate Development	—
Gregory Kiraly Ontario, Canada	52	Chief Operating Officer		Chief Operating Officer	—
Judy McKellar Ontario, Canada	60	Executive Vice President, Chief Human Resources Officer		Executive Vice President, Chief Human Resources Officer	—
Ferio Pugliese Ontario, Canada	48	Executive Vice President, Customer Care and Corporate Affairs		Executive Vice President, Customer Care and Corporate Affairs	—
James Scarlett Ontario, Canada	63	Executive Vice President, Chief Legal Officer		Executive Vice President, Chief Legal Officer	—
Michael Vels Ontario, Canada	55	Chief Financial Officer		Chief Financial Officer	—

Name, Province or State and Country of Residence	Age	Position/Title	Independent	Principal Occupation	Committees
David F. Denison Ontario, Canada	64	Director and Chair of the Board	Yes	Board Chair, Hydro One Limited and Hydro One Inc.	—
Ian Bourne[(1)] Alberta, Canada	69	Director	Yes	Chair, Ballard Power Systems Inc.	Human Resources Committee (Chair); Nominating, Corporate Governance, Public Policy & Regulatory Committee
Charles Brindamour Ontario, Canada	46	Director	Yes	Chief Executive Officer, Intact Financial Corporation	Audit Committee; Human Resources Committee
Marcello (Marc) Caira[(1)] Ontario, Canada	62	Director	Yes	Vice-Chairman, Restaurant Brands International Inc.	Human Resources Committee; Nominating, Corporate Governance, Public Policy & Regulatory Committee
Christie Clark Ontario, Canada	63	Director	Yes	Corporate Director	Human Resources Committee; Nominating, Corporate Governance, Public Policy & Regulatory Committee
George Cooke[(1)] Ontario, Canada	63	Director	Yes	President, Martello Associates Consulting / Chair, OMERS Administration Corporation	Audit Committee; Health, Safety, Environment and First Nations & Métis Committee
Margaret (Marianne) Harris Ontario, Canada	59	Director	Yes	Corporate Director	Human Resources Committee; Health, Safety, Environment and First Nations & Métis Committee (Chair)
James Hinds Ontario, Canada	59	Director	Yes	Corporate Director	Audit Committee; Health, Safety, Environment and First Nations & Métis Committee
Kathryn Jackson[(1)] Pennsylvania, United States	59	Director	Yes	Corporate Director	Nominating, Corporate Governance, Public Policy & Regulatory Committee; Health, Safety, Environment and First Nations & Métis Committee
Roberta Jamieson Ontario, Canada	64	Director	Yes	President and Chief Executive Officer, Indspire	Audit Committee; Health, Safety, Environment and First Nations & Métis Committee
Frances Lankin Ontario, Canada	62	Director	Yes	Corporate Director	Audit Committee; Nominating, Corporate Governance, Public Policy & Regulatory Committee
Philip S. Orsino Ontario, Canada	62	Director	Yes	Corporate Director	Audit Committee (Chair); Nominating, Corporate Governance, Public Policy & Regulatory Committee
Jane Peverett[(1)]	58	Director	Yes	Corporate Director	Human Resources

Name, Province or State and Country of Residence	Age	Position/Title	Independent	Principal Occupation	Committees
British Columbia, Canada					Committee; Nominating, Corporate Governance, Public Policy & Regulatory Committee (Chair)
Gale Rubenstein[1] Ontario, Canada	63	Director	Yes	Partner, Goodmans LLP	Human Resources Committee; Health, Safety, Environment and First Nations & Métis Committee

Notes:

(1) These directors have been designated as the Province's nominees to the board of directors of Hydro One for the purpose of the Governance Agreement.

The following includes a brief profile of each of the executive officers of Hydro One, which include a description of their present occupation and their principal occupations for the past five years. For profiles of each of the directors of Hydro One, see Hydro One Limited's Management Information Circular under the subheading "About the Nominated Directors - Director Profiles".

Mayo Schmidt is the President and Chief Executive Officer of Hydro One. Prior to joining Hydro One, Mr. Schmidt served as President and Chief Executive Officer at Viterra Inc., a global food ingredients company operating in 14 countries. Early in his career, Mr. Schmidt held a number of key management positions of increasing responsibility at General Mills, Inc. until he joined ConAgra as President of their Canadian operations and spearheaded ConAgra's expansion into Canada. In 2007, he led a $2.0 billion acquisition of Agricore United, then a $2.2 billion acquisition of ABB, Australia's leading agriculture corporation, growing Viterra Inc. from a $200 million market capitalization to finally a sale in 2012 for over $7.5 billion. Mr. Schmidt currently sits on the Board of Directors of Agrium Inc. as Chairman of the Governance Committee and Chairman of the Special Committee for the Merger of Equals of Agrium and Potash Corp. forming a $38 billion global fertilizer giant. He is a member of Harvard University Private and Public, Scientific, Academic and Consumer Food Policy Group, and is on Washburn University's Foundation Board of Trustees. Mr. Schmidt received his Honorary Doctorate of Commerce from Washburn in 2016 and his B.B.A. from Washburn in 1980.

Effective September 1, 2016, Paul Barry was appointed to the role of Executive Vice President, Strategy and Corporate Development of Hydro One Networks Inc. Mr. Barry has significant strategy, business development and financial expertise in the electric power, natural gas, and water utility sectors. Mr. Barry was recently Chief Executive Officer and founding partner of Public Infrastructure Partners LLC, a power and utility strategic advisor to leading private equity, infrastructure, and pension funds in the U.S., Canada, and Europe. Mr. Barry's prior executive leadership roles include Senior Vice President and Chief Development Officer, Head of Mergers & Acquisitions, and President of the commercial and international business for Duke Energy Corporation. At Duke Energy, Mr. Barry was responsible for executing over $50 billion of strategic transactions that transformed the company into the largest electric utility in North America. He served as CFO for Pepco Holdings, a Fortune 500 mid-Atlantic utility based in Washington, D.C., and was Vice President, Business Development, Energy Financial Services, for General Electric Company. Mr. Barry also served as Senior Advisor, City of Los Angeles, Department of Water and Power (LADWP), the largest municipal electric and water utility in the U.S., and as Executive Vice-President and Chief Financial Officer of Kinross Gold Corporation. Mr. Barry earned an MBA from Harvard Business School, where he also attended the Executive Program, and a Bachelor of Science, magna cum laude, in Finance from Northeastern University.

Effective September 12, 2016, Gregory Kiraly was appointed to the role of Chief Operating Officer

(COO) of Hydro One. As COO, Mr. Kiraly oversees the transmission and distribution value chain including Planning, Engineering, Construction, Operations, Maintenance, and Forestry; Shared Services functions including Facilities, Real Estate, Fleet, and Procurement; and the Telecom and Remote Communities subsidiaries. Mr. Kiraly is a power and utilities executive with 30 years of experience. He has an extensive background in energy transmission and distribution, in both electricity and gas, having served in various executive leadership roles across three of the largest investor-owned utilities in the U.S.; Pacific Gas and Electric (PG&E), Commonwealth Edison (ComEd), and Public Service Electric & Gas Company (PSE&G). Mr. Kiraly most recently held the role of Senior Vice President, Electric Transmission and Distribution for PG&E in San Francisco, and also served in several other key executive assignments over the past eight years. Prior to joining PG&E, Mr. Kiraly held executive-level positions at Capital Commonwealth Edison (Exelon) in Chicago from 2000-2008 in the areas of Distribution System Operations, Construction and Maintenance, and Energy Delivery. Prior to ComEd, Mr. Kiraly started his career at PSE&G in New Jersey, having served in various leadership roles over 15 years, where his accountabilities focused on Health and Safety, Electric and Gas Distribution.

Judy McKellar is the Executive Vice President, Chief Human Resources Officer of Hydro One Inc. She was appointed to this position on November 11, 2016. Ms. McKellar has held various roles of increasing responsibility at Hydro One Networks Inc., an indirect subsidiary of Hydro One Limited, in the Human Resources department over her 30+ year career and was appointed VP of Human Resources in 2010. In 2014, she assumed the additional responsibility of Senior Vice President of People and Culture/Health, Safety and Environment and serves as the accountable executive for the Human Resources Committee of the Board of Directors. Ms. McKellar earned a Bachelor of Arts degree from Victoria College, University of Toronto and was recently named as one of 2015's 100 Most Powerful Women in Canada by PricewaterhouseCoopers in the "Public Sector" category.

Effective September 9, 2016, Ferio Pugliese was appointed to the role of Executive Vice President, Customer Care and Corporate Affairs of Hydro One Networks Inc. Prior to his appointment, Mr. Pugliese held progressively senior leadership roles in hospitality, pulp and paper and airline industries with responsibility for human resources, operations and customer service. Since 2007, Mr. Pugliese was a member of the Executive Leadership team at Westjet Airlines serving as WestJet's Executive Vice President People, Culture and Inflight Services and in 2013 led the launch and successful operation of the company's regional airline as President of WestJet Encore. WestJet Encore was recognized for having the continent's top on-time performance for regional airlines in 2015. Mr. Pugliese is highly recognized as a market leader in customer service and brings expertise in building and leading a winning culture focused on serving customers and communities. Mr. Pugliese was recognized by Caldwell Partners as one of Canada's Top 40 under 40 in 2007. He holds a Master of Arts degree in Adult Education from Central Michigan University, an Honours Bachelor of Arts degree in Social Science and an Honours Bachelor of Commerce degree from the University of Windsor.

Effective September 1, 2016, James Scarlett was appointed as Executive Vice President and Chief Legal Officer of Hydro One. Prior to joining Hydro One, Mr. Scarlett was a Senior Partner at Torys LLP. He joined Torys in March 2000 and held a number of leadership roles at the firm, including head of Torys' Capital Markets Group, Mining Group and International Business Development Strategy. Mr. Scarlett was also a member of the firm's Executive Committee from 2009-2015. Prior to joining Torys, Mr. Scarlett was a partner at another major Canadian law firm. While at that firm Mr. Scarlett held leadership roles as head of its Corporate Group, Securities Group and as a member of its Board. Mr. Scarlett was also seconded to the Ontario Securities Commission in 1987 and was appointed as the first Director of Capital Markets in 1988, a position he held until his return to private law practice in 1990. Mr. Scarlett is currently a director of Camp Oochigeas, a charity for kids with cancer. Mr. Scarlett earned his law degree (J.D.) from the University of Toronto in 1981 and his Bachelor of Commerce Degree from the University of McGill in 1975. He is highly recognized in his profession having been consistently and repeatedly named to numerous prestigious lists and rankings. In 2015, Mr. Scarlett earned his ICD.D (Institute of Corporate Directors) designation.

Michael Vels is the Chief Financial Officer of Hydro One. Before joining Hydro One, Mr. Vels was the Chief Financial Officer for Maple Leaf Foods Inc. Mr. Vels had over 20 years of experience with Maple Leaf Foods Inc. where he was responsible for leading organizational change, multiple capital market transactions, business acquisitions and divestitures, information technology transformations and restructurings. He also served on the board of directors of Maple Leaf Foods Inc.'s public traded subsidiary, Canada Bread Company, Limited. Mr. Vels led complex multi-divisional finance teams, information solutions and communications and investor relations functions and has considerable experience with mergers, acquisitions and divestitures. He currently serves on the Board of Directors of Canada's National Ballet School. Mr. Vels earned a Bachelor of Accountancy from the University of Witwatersrand, in Johannesburg, South Africa. He is a Chartered Accountant (South African Institute of Chartered Accountants) and he has earned his ICD.D (Institute of Corporate Directors) designation.

Information Regarding Certain Directors and Executive Officers

As at December 31, 2016, the directors and executive officers of Hydro One Limited beneficially owned, controlled or directed, directly or indirectly, as a group, 128,608 common shares, which represented approximately 2% of the outstanding common shares.

Corporate Cease Trade Orders and Bankruptcies

Except as described below:

- none of the directors or executive officers of Hydro One Limited is, or within the last 10 years has served as, a director or executive officer of any company that, during such service or within a year after the end of such service, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets;

- none of the directors or executive officers of Hydro One Limited is, or within the last 10 years has served as, a director, chief executive officer or chief financial officer of any company that, during such service or as a result of an event that occurred during such service, was subject to an order (including a cease trade order, or similar order or an order that denied access to any exemption under securities legislation), for a period of more than 30 consecutive days; or

- none of the directors or executive officers of Hydro One Limited nor any shareholder holding shares sufficient to materially affect control of Hydro One Limited, within the last 10 years has become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director.

In May 2004, Saskatchewan Wheat Pool Inc., a predecessor to Viterra Inc., initiated a disposition of its hog operations, which had been carried on through certain of its subsidiaries, through a court supervised process under the *Companies' Creditors Arrangement Act* (Canada). On April 12, 2005, the Saskatchewan Financial Services Commission issued a cease trade order against four of these subsidiaries for failing to file the required annual continuous disclosure documents. The cease trade order was revoked on October 18, 2010 pursuant to Viterra Inc.'s application to effect a re-organization of the entities in question. Mr. Schmidt served as an officer and/or director of these entities at the time.

Mr. Orsino was a director of CFM Corporation from July 2007 until his resignation in March 2008. In April 2008, CFM filed for protection under the *Companies' Creditors Arrangement Act* (Canada).

Ms. Peverett was a director of Postmedia Network Canada Corp. between April 2013 and January 2016. On October 5, 2016, within one year of Ms. Peverett's resignation from the board of directors, Postmedia completed a recapitalization transaction (the *recapitalization transaction*) pursuant to a court approved plan of arrangement under the *Canada Business Corporations Act*. As part of the recapitalization transaction, approximately US $268.6 million of debt was exchanged for shares that represented approximately 98% of the outstanding shares at that time. Additionally, Postmedia repaid, extended and amended the terms of its outstanding debt obligations pursuant to the recapitalization transaction.

Penalties or Sanctions

None of the directors or executive officers of Hydro One Limited, nor any shareholder holding shares sufficient to materially affect control of Hydro One Limited, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

Conflicts of Interest

To the best of the Company's knowledge, there are no existing potential conflicts of interest among the Company and the directors or executive officers of the Company as a result of their outside business interests as at the date of this annual information form. Certain of the directors and executive officers serve as directors and executive officers of other public companies. Accordingly, conflicts of interest may arise which could influence these persons in evaluating possible acquisitions or in generally acting on behalf of the Company.

Indebtedness of Directors and Executive Officers

No director, executive officer, employee, former director, former executive officer or former employee or associate of any director or executive officer of Hydro One Limited or any of its subsidiaries had any outstanding indebtedness to Hydro One Limited or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by Hydro One Limited or any of its subsidiaries.

AUDIT COMMITTEE

The Audit Committee must consist of at least three directors, all of whom are persons determined by Hydro One to be both "independent" (within the meaning of all Canadian securities laws and stock exchange requirements and the Governance Agreement) and "financially literate" (within the meaning of other applicable requirements or guidelines for audit committee service under securities laws or the rules of any applicable stock exchange, including National Instrument 52-110 – *Audit Committees*). At least one member of the Audit Committee will qualify as an "audit committee financial expert" as defined by the applicable rules of the United States Securities and Exchange Commission. The Audit Committee comprises Philip S. Orsino (Chair), Charles Brindamour, George Cooke, James Hinds, Roberta Jamieson and Frances Lankin. Each of the audit committee members has an understanding of the accounting principles used to prepare Hydro One's financial statements and varied experience as to the general application of such accounting principles, as well as an understanding of the internal controls and procedures necessary for financial reporting.

The Board has adopted a written charter for the Audit Committee, in the form set out under Schedule "A" hereto, which sets out the Audit Committee's responsibilities.

Relevant Education and Experience

Charles Brindamour

Mr. Charles Brindamour is the Chief Executive Officer of Intact Financial Corporation, Canada's largest property and casualty insurance provider. Mr. Brindamour began his career with Intact in 1992 as an actuary and held over the years a number of progressive management positions. Under Mr. Brindamour's leadership, the company became an independent and widely-held Canadian company in 2009 and two years later engineered the acquisition of AXA Canada; the largest acquisition in the history of Canada's property and casualty insurance industry. Mr. Brindamour is a board member of Intact Financial Corporation, the C.D. Howe Institute, the Geneva Association, the Business Council of Canada and Branksome Hall. He is also a member of the Advisory Committee of the University of Waterloo's Climate Change Adaptation Project, serves on the advisory board of Gibraltar Growth Corporation and is co-chair of Laval University's "Grande Campagne". Mr. Brindamour is a graduate of Laval University in Actuarial Sciences and an associate of the Casualty Actuarial Society.

George L. Cooke

Mr. George Cooke is a corporate director and the Chair of the board of directors of the OMERS Administration Corporation, CANATICS (Canadian National Insurance Crime Services) and the Ontario Lottery and Gaming Corporation. OMERS is one of Canada's largest pension funds and OMERS Administration Corporation is responsible for pension services and administration, investments, and plan valuation. Mr. Cooke is the former President and CEO of The Dominion of Canada General Insurance Company (The Dominion), formerly a property and casualty insurance company, a position he held from 1992 to August 2012. In August 2012, Mr. Cooke retired from his role as President of The Dominion and continued to hold the position of Chief Executive Officer of the company until December 31, 2012. Mr. Cooke obtained a Bachelor of Arts degree (Hons.) in Political Studies and a Masters of Business Administration degree from Queen's University. He also holds an Honorary Doctor of Laws degree from Assumption University in Windsor. Mr. Cooke was a member of the Board of Directors of The Dominion (1992-2013), the Insurance Bureau of Canada (1992-2013), E-L Financial Corporation (1992-2012), Empire Life (1992-2002) and Atomic Energy of Canada Limited (1995-1999), and he was also Executive Vice-President with E-L Financial Corporation Limited (1992-2013).

James Hinds

Mr. James Hinds is a corporate director. He is also a director of Allbanc Split Corp., a mutual fund company. He is a retired investment banker, having previously served as Managing Director of TD Securities Inc., prior to which he held positions at CIBC Wood Gundy Inc. and Newcrest Capital Inc. Mr. Hinds was the past chair of the Independent Electricity System Operator (IESO), a Crown corporation responsible for operating the electricity market, and was also chair of the former Ontario Power Authority Board of Directors (2010-2014) until its merger with the IESO effective January 1, 2015. Mr. Hinds was a member of the Audit Committee of the Board of Directors of both the IESO and Ontario Power Authority. Mr. Hinds received a Bachelor of Arts degree from Victoria College at the University of Toronto, a Master of Business Administration from the Wharton School of Business and a law degree from the University of Toronto Law School.

Roberta L. Jamieson

Ms. Roberta Jamieson is a Mohawk woman from the Six Nations of the Grand River Territory in Ontario, where she still resides. She is also President and Chief Executive Officer of Indspire, Canada's premiere Indigenous-led charity, and Executive Producer of the Indspire Awards, a nationally broadcast gala honoring Indigenous achievement. Ms. Jamieson was the first First Nations woman to earn a law degree in Canada; the first non-parliamentarian appointed an ex-officio member of a House of Commons Committee; the first woman Ombudsman of Ontario (1989-1999); and in December 2011, she was the first woman elected Chief of the Six Nations of the Grand River Territory. She was also a Director of the Ontario Power Generation Inc. Board of Directors (2012-2015) and served on its Risk Oversight Committee. Ms. Jamieson was appointed a Member of the Order of Canada in 1994 and promoted to an Officer in 2016. Ms. Jamieson holds a Bachelor of Laws from the University of Western Ontario.

Hon. Frances L. Lankin, P.C., C.M.

Hon. Frances Lankin is a corporate director. She was the former President and CEO of the United Way Toronto (2001-2010), a Toronto-based charity. In 2009, Ms. Lankin was appointed to the Queen’s Privy Council for Canada and served for five years as a member of the Security Intelligence Review Committee. In 2014, Ms. Lankin was appointed to the Premier’s Advisory Council on Government Assets whose mandate was to review and identify opportunities to modernize government business enterprises, and in 2011 and 2012, she co-led a review of Ontario’s social assistance system as part of the province’s poverty reduction strategy. During her first term as an elected Member of Provincial Parliament, Ms. Lankin served in a variety of Cabinet roles including Chair of Management Board, Minister of Health and Long-Term Care, and Minister of Economic Development and Trade. Ms. Lankin is a Director of the Ontario Lottery and Gaming Corporation and Chair of the Social Responsibility Committee of the Board. She is the former Chair of the National NewsMedia Council, and a former Director of the Institute of Corporate Directors, where she sat on the Audit Committee. Additionally, she sat on the Ontario Hospital Association’s Audit Committee from 2012-2013. Ms. Lankin was appointed a Member of the Order of Canada in 2012. In April of 2016, Ms. Lankin was appointed to the Senate of Canada where she sits as an Independent Senator from Ontario. Ms. Lankin serves on the Senate Committee on Internal Economy, Budgets and Administration.

Philip S. Orsino, O.C., FCPA, FCA

Mr. Philip S. Orsino is a corporate director. He was the President and Chief Executive Officer of Jeld-Wen Inc., a global integrated manufacturer of building products from 2011 until he retired in 2014. Formerly until October 2005, Mr. Orsino was the President and Chief Executive Officer of Masonite International Corporation for 22 years. Mr. Orsino is a director of The Bank of Montreal and Chair of its Audit and Conduct Review Committee and a director of The Minto Group, a private real estate developer, and chair of the Audit Committee. He was the recipient of the 2003 Canada's Outstanding CEO of the Year Award and received the University of Toronto's Distinguished Business Alumni Award for 2002. He is a Fellow of the Institute of Chartered Accountants and holds a degree from Victoria College at the University of Toronto. Mr. Orsino was appointed an Officer of the Order of Canada in 2004.

Pre-Approval Policies and Procedures

The Audit Committee Charter requires that all non-audit services to be provided to Hydro One Limited or any of its subsidiaries by the external auditors or any of its affiliates are subject to pre-approval by the Audit Committee.

Auditors’ Fees

The aggregate fees billed by KPMG to Hydro One and its subsidiaries in 2016 and 2015 for professional services are presented below:

	Year ended December 31, 2016	Year ended December 31, 2015
Audit Fees(1)	$1,524,814(2)	$1,376,500(3)
Audit-Related Fees(4)	$488,854	$ 412,200
Tax Fees:		
SR&ED(5) **Tax Credit Claim**	$90,000	$90,000
General Tax Advice	$57,500	N/A
Other Fees(6)	$413,643	N/A
Total	**$2,574,811**	**$1,878,700**

Notes:

(1) The nature of the services rendered was: audit of annual financial statements of the Company and its subsidiaries, and statutory and regulatory filings.

(2) Additional services in 2016 included: IFRS reporting to the Province, audit of annual financial statements of acquired companies and audit of financial system enhancements and complex accounting.

(3) $475,000 of these fees related to the company’s initial public offering completed on November 5, 2015, which are recoverable from the Province.

(4) The nature of the services rendered was: translations and audit of the Hydro One Pension Plan and related services reasonably related to the performance of the audit or review of the Company’s financial statements that are not reported under Audit Fees.

(5) Scientific Research and Experimental Development.

(6) The nature of the services rendered was: due diligence activities.

PROMOTERS

Hydro One Inc. has taken the initiative in founding and organizing Hydro One Limited and may therefore be considered a promoter of Hydro One Limited for the purposes of applicable securities legislation. In connection with a series of pre-closing transactions completed in connection with the initial public offering of Hydro One Limited, on October 31, 2015, Hydro One Limited acquired all of the issued and outstanding common shares of Hydro One Inc. from the Province in exchange for the issuance to the Province of 16,720,000 Series 1 preferred shares and 12,197,500,000 common shares. See “Corporate Structure – Corporate Structure and Subsidiaries”, “General Development of the Business” and “Business of Hydro One – Reorganizations”.

Although the Province was identified as a promoter of Hydro One for purposes of the initial public offering, as a result of the entering into of the Governance Agreement and completion of the initial public offering, Hydro One no longer believes the Province is a promoter of Hydro One.

AGREEMENTS WITH PRINCIPAL SHAREHOLDER

In connection with the November 2015 completion of the initial public offering of Hydro One Limited, on November 5, 2015, Hydro One and the Province entered into:

- the Governance Agreement to address the Province’s role in the governance of Hydro One Limited; and
- the Registration Rights Agreement to provide the Province with the right to require Hydro One Limited to facilitate future secondary offerings of common shares or preferred shares owned or controlled by the Province.

The material terms of the Governance Agreement and the Registration Rights Agreement are summarized below. A copy of each of the Governance Agreement and the Registration Rights Agreement has been filed on SEDAR and is available under Hydro One Limited's profile at www.sedar.com. The discussion in this annual information form concerning the Governance Agreement and the Registration Rights Agreement is not complete, and is qualified in its entirety to the text of the Governance Agreement and the Registration Rights Agreement, each of which should be referred to. Not all of the terms of the Governance Agreement and the Registration Rights Agreement are described in this annual information form.

Governance Agreement

Governance Matters

The Governance Agreement specifically addresses the following governance matters:

- The governance principles under which Hydro One Limited and its subsidiaries will be managed and operated.
- The nomination of directors, which includes: (i) the requirement for a fully independent board of directors (other than the Chief Executive Officer), and (ii) the maximum number of directors that may be nominated by the Province.
- The election and replacement of directors.
- Approvals requiring a special resolution of the directors.

Governance Principles

The Governance Agreement provides that the business and affairs of Hydro One Limited will be managed and operated in accordance with certain governance principles.

The governance principles provide that:

- Hydro One Limited will maintain corporate governance policies, procedures and practices consistent with the best practices of leading Canadian publicly listed companies, having regard to Hydro One Limited's ownership structure and the Governance Agreement.
- The board of directors of Hydro One Limited is responsible for the management of the business and affairs of Hydro One Limited.
- With respect to its ownership interest in Hydro One Limited, the Province will engage in the business and affairs of Hydro One Limited as an investor and not a manager, and the Province intends to achieve its policy objectives through legislation and regulation, as it would with respect to any other utility operating in Ontario.

Nomination of Directors

The Governance Agreement establishes qualification standards for director nominees, provides for the number of directors that may be nominated and establishes a process for confirming nominees. The Governance Agreement recognizes that the Board is to be a fully independent board (independent of both Hydro One and the Province), except the Chief Executive Officer, as described under the subheading " – Independence" below.

Director Qualification Standards

Under the Governance Agreement, the Province and the Nominating, Corporate Governance, Public Policy & Regulatory Committee have agreed to nominate as directors, qualified individuals of high quality and integrity who have the experience, expertise and leadership appropriate to manage a business of the complexity, size and scale of the business of Hydro One Limited, on a basis consistent with the highest standards for directors of Canada's leading public companies.

In addition, a majority of the directors must be resident Canadians (as defined in the OBCA).

Independence

Each director nominee must, among other things:

- be independent of Hydro One Limited (other than the Chief Executive Officer) within the meaning of Ontario securities laws governing the disclosure of corporate governance practices;

- be independent of the Province (other than the Chief Executive Officer). A director will be independent of the Province if he or she would be independent of Hydro One Limited within the meaning of Ontario securities laws governing the disclosure of corporate governance practices if the Province and each Specified Provincial Entity were treated as Hydro One Limited's parent under that definition, but excluding, in the case only for the current directors, any prior relationship that ended before August 31, 2015. In addition, he or she may not be an employee or official of the Province or any Specified Provincial Entity, either: (i) currently or, (ii) within the last three years (excluding in the case of (ii), the current directors whose prior relationship ended before August 31, 2015); and

- meet the requirements of applicable securities and other laws and any exchange on which the voting securities are listed.

A "Specified Provincial Entity" means (1)(a) the Ontario Financing Authority, (b) the IESO, (c) Ontario Power Generation Inc., (d) the Electrical Safety Authority, (e) Ontario Electricity Financial Corporation, (f) Infrastructure Ontario, or (g) a subsidiary of, or a person controlled by, any organization listed in (a) to (f); and (2) the OEB.

Number of Directors

Under the articles of Hydro One Limited and pursuant to the terms of the Governance Agreement, the Board will consist of no fewer than 10 and no more than 15 directors, with the initial Board consisting of 15 directors until the first annual meeting of shareholders following the completion of the initial public offering of Hydro One Limited.

Board Nominees

The nominees to be proposed for election to the Board by Hydro One Limited at annual meetings of shareholders will be determined as follows:

- The Chief Executive Officer will be nominated.

- The Province will be entitled to nominate that number of nominees equal to 40% of the number of directors to be elected (rounded to the nearest whole number), subject to certain exceptions.

- The Nominating, Corporate Governance, Public Policy & Regulatory Committee will nominate the remaining directors.

Board Nomination Process

Under the Governance Agreement, the Province and representatives of the Nominating, Corporate Governance, Public Policy & Regulatory Committee are to meet after each annual meeting of shareholders to discuss expected upcoming departures from the Board (whether due to resignation, retirement or otherwise) and the impact such departures will have on the Board, having regard to continued compliance with the Governance Agreement and the ability of the Board to satisfy the Board's skills matrix, diversity policy and other governance standards. Under the Governance Agreement, at this meeting the Nominating, Corporate Governance, Public Policy & Regulatory Committee is to make recommendations to the Province respecting potential candidates for director, including potential candidates for nomination by the Province. The Province has no obligation to nominate any of the individuals recommended as one of its director nominees.

Not later than 60 days prior to the date by which proxy solicitation materials must be mailed for Hydro One's annual meeting of shareholders, each of the Province and the Nominating, Corporate Governance, Public Policy & Regulatory Committee will notify the other of its proposed director nominees. If a proposed nominee is not already a director of Hydro One or is then a director but whose circumstances have materially changed in a way that would affect whether she or he would continue to meet the director qualification standards under the Governance Agreement, then the Province or the committee, as the case may be, will have 10 business days to confirm that nominee or reject that nominee on the basis that the nominee does not meet those director qualification standards.

If a director nominee of the Province or the Nominating, Corporate Governance, Public Policy & Regulatory Committee is rejected, then the Province or the committee will be entitled to nominate additional candidates until a nominee is confirmed by the other. If no replacement nominee is confirmed for a director who was expected to depart from the board and that director does not resign, that director shall be re-nominated. The Province and the committee will use commercially reasonable efforts to confirm director nominees prior to the date by which proxy solicitation materials must be mailed for the annual meeting of shareholders.

<u>Election and Replacement of Directors</u>

The Governance Agreement provides for how:

- the Province will vote with respect to director nominees, including its nominees and those of the Nominating, Corporate Governance, Public Policy & Regulatory Committee,
- the Province may vote at contested elections,
- the Province may seek to replace the Board by withholding votes or voting for removal, and
- Board vacancies will be filled.

Voting on Director Elections

At any meeting of shareholders to elect directors, the Province is required to vote in favour of the nominees selected by the Province and the Nominating, Corporate Governance, Public Policy & Regulatory Committee in accordance with the board nomination process set out in the Governance Agreement, except in the case of contested director elections or where the Province seeks to replace the Board in accordance with the Governance Agreement.

Contested Elections

At any meeting of shareholders to elect directors of Hydro One Limited at which there are more nominees for directors than there are directors to be elected, the Province may vote its Voting Securities in its sole discretion (including to vote in favour of other candidates instead of the Province's nominees), except that the Province will vote in favour of the election of the Chief Executive Officer as a director.

Right to Withhold Votes

The Province is required under the Governance Agreement to vote in favour of all director nominees of Hydro One Limited, subject to the Province's overriding right to withhold from voting in favour of all director nominees and its right to seek to remove and replace the entire Board, including in each case its own director nominees but excluding the Chief Executive Officer and, at the Province's discretion, the Chair. Depending on the number of withheld votes a director nominee receives at a meeting of shareholders at which directors are to be elected, that director nominee may be required to tender his or her resignation to the Board in accordance with Hydro One Limited's majority voting policy.

Province's Right to Replace the Board

The Province may at any time notify Hydro One Limited that it intends to request that Hydro One Limited hold a meeting of shareholders for the purposes removing all of the directors in office, including those nominated by the Province, with the exception of the Chief Executive Officer and, at the sole discretion of the Province, the Chair (a "Removal Notice"). If the Province gives Hydro One a Removal Notice, then the Chair shall coordinate the establishment of an ad hoc nominating committee comprising one representative of each of the five largest beneficial owners of Voting Securities known to the Company (or if at least three such owners are not willing to provide a representative, then the individuals the Province proposes to nominate as replacement directors). The Province and the ad hoc nominating committee will identify and confirm replacement directors to be nominated at the shareholders' meeting pursuant in accordance with the process set out in the Governance Agreement. Each replacement director nominee must meet the same qualification and independence standards under the Governance Agreement as for any director nominee. Hydro One Limited will call the shareholders' meeting once the replacement director nominees are confirmed pursuant to this process, and will hold the shareholders' meeting within 60 days of this confirmation. At the shareholders' meeting, the Province will vote in favour of removing the current directors with the exception of the Chief Executive Officer and, at the Province's discretion, the Chair, and will vote in favour of the new independent director nominees.

Board Approvals Requiring a Special Resolution of the Directors

The Governance Agreement provides that certain actions require approval by a resolution of the Board passed by at least two-thirds of the votes cast at a meeting of the directors, or consented to in writing by all of the directors (a "Special Board Resolution"). Matters requiring approval by a Special Board Resolution include:

- the appointment and annual confirmation of the Chair,
- the appointment and annual confirmation of the Chief Executive Officer, and
- changes to certain specified governance standards specified in the Governance Agreement to be "Hydro One's governance standards".

The governance standards subject to this special approval requirement include the Board's skills matrix, the Ombudsman's Mandate, the Diversity Policy and the Majority Voting Policy, the Corporate Governance Guidelines, the mandates of the Board and its committees, position descriptions for the Chief Executive Officer, the Chair, the directors and committee chairs, and the Stakeholder Engagement Policy.

Other Matters

In addition to the governance matters noted above, the Governance Agreement also addresses the following matters:

- Restrictions on the right of the Province to initiate fundamental changes.
- Pre-emptive rights provided to the Province with respect to future issuances of Voting Securities by Hydro One Limited.
- Acquisition limits with respect to the Province's acquisition of outstanding Voting Securities.

Restrictions on Province's Right to Initiate Fundamental Changes

The Province has agreed not to initiate a fundamental change to Hydro One Limited (as defined in Part XIV of the OBCA), including not to initiate any arrangement or amalgamation involving Hydro One Limited or any amendment to the articles of Hydro One Limited. The Province may, however, vote its Voting Securities as it sees fit in the event any fundamental change is initiated by Hydro One Limited or another shareholder of Hydro One Limited.

Pre-emptive Rights

Hydro One Limited has granted to the Province a pre-emptive right to acquire additional Voting Securities as part of future offerings by Hydro One Limited of Voting Securities. If Hydro One Limited proposes to issue Voting Securities in the future, whether pursuant to a public offering or a private placement, Hydro One Limited must notify the Province of the proposal and provide information in accordance with the provisions of the Governance Agreement at least 30 days in advance and must offer the Province the right to purchase up to 45% of the Voting Securities being offered. Any Voting Securities not purchased by the Province pursuant to the offer may be purchased by any other person pursuant to the proposed offering.

The pre-emptive right also applies with respect to any proposed issuance by Hydro One Limited of securities convertible into or exchangeable for Voting Securities except securities convertible into or exchangeable for Voting Securities: (i) pursuant to certain employee or director compensation plans; (ii) pursuant to any dividend re-investment arrangement of the Company that is consistent with dividend reinvestment arrangements of other publicly traded utilities in Canada (including as to discount rates) and that does not include a cash purchase option; (iii) pursuant to a rights offering that is open to all shareholders of Hydro One Limited; or (iv) pursuant to any business combination, take-over bid, arrangement, asset purchase transaction or other acquisition of assets or securities of a third party.

45% Acquisition Limit

The Province has agreed in the Governance Agreement, subject to certain exceptions, not to acquire previously issued Voting Securities if after that acquisition, the Province would own more than 45% of any class or series of Voting Securities. This restriction does not limit the Province from acquiring Voting Securities on an issuance by Hydro One Limited, including pursuant to the exercise by the Province of its pre-emptive right. See "Agreements with Principal Shareholder – Governance Agreement – Other Matters – Pre-emptive Rights" above.

Registration Rights Agreement

Demand Registration

Pursuant to the Registration Rights Agreement, Hydro One Limited has granted the Province certain demand registration rights providing that, from time to time while the Province is a "control person" of Hydro One Limited within the meaning of applicable Canadian securities laws, the Province can require Hydro One Limited to file, at the expense of the Province (except for internal expenses of Hydro One Limited or other expenses that Hydro One Limited would have incurred in the absence of such a request), and subject to certain exceptions, one or more prospectuses and take other procedural steps as may be reasonably necessary to facilitate a secondary offering in Canada of all or any portion of the common shares or preferred shares ("**shares**") held by the Province.

"Piggy-Back" Registration

If Hydro One Limited proposes to undertake a Canadian public offering by prospectus, the Province is entitled, while it is a "control person" of Hydro One Limited within the meaning of applicable Canadian securities laws, to include shares owned by it as part of that offering, provided that the underwriters may reduce the number of shares proposed to be sold if in their reasonable judgment all of the shares proposed to be offered by Hydro One Limited and the Province may not be sold in an orderly manner within a price range reasonably acceptable to Hydro One Limited. In that case, the shares to be sold will be allocated pro rata between Hydro One Limited and the Province based on their relative proportionate number of shares requested to be included in the offering. Hydro One Limited and the Province will share the expenses of the offering (except for internal expenses of Hydro One Limited) in proportion to the gross proceeds they each receive from the offering.

Private Placements

Hydro One Limited has also agreed to use commercially reasonable efforts to assist, at the Province's expense, the Province in any sale by it of shares of Hydro One Limited pursuant to an exemption from the prospectus requirements, in the preparation of an offering memorandum and other documentation and by facilitating due diligence by the prospective buyer.

Customary Agreements

Hydro One Limited and the Province have also agreed to enter into customary agreements, including "lock-up" agreements, on customary market terms in connection with such transactions. Hydro One Limited also agreed to certain indemnification and contribution covenants in favour of the Province and any underwriters involved in such transactions.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as noted below and elsewhere in this annual information form, there are no material interests, direct or indirect, of any director or executive officer of the Company, any shareholder that beneficially owns, or controls or directs (directly or indirectly), more than 10% of any class or series of Hydro One Limited's outstanding voting securities, or any associate or affiliate of any of the foregoing persons, in any transaction within the three years before the date hereof that has materially affected or is reasonably expected to materially affect the Company.

Relationships with the Province and Other Parties

Overview

The Province is Hydro One Limited's principal shareholder. The OEB is the principal regulator of

Ontario's electricity industry. The Province appoints the board members of the OEB and fills any vacancies on the OEB. The OEB is obligated to implement approved directives of the Province concerning general policy and objectives to be pursued by the OEB and other directives aimed at addressing existing or potential abuses of market power by industry participants. The IESO, among other matters, directs the operation of the Ontario power system by balancing supply and demand of electricity and directing electricity flow and assumed the responsibility for forecasting supply and demand of electricity over the medium and long term to meet the needs of the province. The board of directors of the IESO, other than its Chief Executive Officer, is appointed by the Province in accordance with the regulations in effect from time to time under the Electricity Act.

In connection with the initial public offering of Hydro One Limited, the Company entered into the Governance Agreement and the Registration Rights Agreement with the Province. See "Agreements with Principal Shareholder".

Transfer Orders

The transfer orders pursuant to which Hydro One Inc. acquired Ontario Hydro's electricity transmission, distribution and energy services businesses as of April 1, 1999, did not transfer certain assets, rights, liabilities or obligations where the transfer would constitute a breach of the terms of any such asset, right, liability or obligation or a breach of any law or order (the "trust assets"). The transfer orders also did not transfer title to assets located on Reserves, which assets are held by the Ontario Energy Financial Corporation. For more information, see the Annual MD&A under the subheading "Risk Management and Risk Factors – Risk from Transfer of Assets Located on Reserves".

Hydro One is obligated under the transfer orders to manage both the trust assets (until it has obtained all consents necessary to complete the transfer of title to these assets to Hydro One) and the assets otherwise retained by the Ontario Electricity Financial Corporation that relate to Hydro One's businesses. Hydro One has entered into an agreement with the Ontario Electricity Financial Corporation under which it is obligated, in managing these assets, to take instructions from the Ontario Electricity Financial Corporation if Hydro One's actions could have a material adverse effect on the Ontario Electricity Financial Corporation. The Ontario Electricity Financial Corporation has retained the right to take control of and manage the assets, although it must notify and consult with Hydro One before doing so and must exercise its powers relating to the assets in a manner that will facilitate the operation of Hydro One's businesses. The consent of the Ontario Electricity Financial Corporation is also required prior to any disposition of these assets.

The Province also transferred officers, employees, assets, liabilities, rights and obligations of Ontario Hydro in a similar manner to its other successor transferees. These transfer orders include a dispute resolution mechanism to resolve any disagreement among the various transferees with respect to the transfer of specific assets, liabilities, rights or obligations.

The transfer orders do not contain any representations or warranties from the Province or the Ontario Electricity Financial Corporation with respect to the transferred officers, employees, assets, liabilities, rights and obligations. Furthermore, under the Electricity Act, the Ontario Electricity Financial Corporation was released from liability in respect of all assets and liabilities transferred by the transfer orders, except for liability under Hydro One's indemnity from the Ontario Electricity Financial Corporation. The parties, with the consent of the Minister of Finance, agreed to terminate such indemnity effective October 31, 2015. By the terms of the transfer orders, each transferee indemnifies the Ontario Electricity Financial Corporation with respect to any assets and liabilities related to that transferee's business not effectively transferred, and is obligated to take all reasonable measures to complete the transfers where the transfers were not effective.

Hydro One has indemnified the Ontario Electricity Financial Corporation in respect of the damages, losses, obligations, liabilities, claims, encumbrances, penalties, interest, taxes, deficiencies, costs and expenses arising from matters relating to the Company's business and any failure by Hydro One to comply with its obligations to the Ontario Electricity Financial Corporation under agreements dated as of April 1, 1999. These obligations include obligations to employ the employees transferred to Hydro One under the transfer orders, make and remit employee source deductions (including tax withholding amounts, and employer contributions), manage the real and personal properties which the Ontario Electricity Financial Corporation continues to hold in trust or otherwise and take any necessary action to transfer all of these properties to the Company, to pay realty taxes and other costs, provide access to books and records and to assume other responsibilities in respect of the assets held by the Ontario Electricity Financial Corporation in trust for the Company.

Departure Taxes

By virtue of being wholly owned by the Province, Hydro One was exempt from tax under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario). However, under the Electricity Act, Hydro One was required to make payments in lieu of tax to the Ontario Electricity Financial Corporation. The payments in lieu of tax were, in general, based on the amount of tax that Hydro One would otherwise be liable to pay under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) if it was not exempt from taxes under those statutes.

In connection with the initial public offering of Hydro One Limited, Hydro One's exemption from tax under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) ceased to apply. Under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), Hydro One was deemed to have disposed of its assets immediately before it lost its tax exempt status resulting in Hydro One making payments in lieu of tax under the Electricity Act totalling $2.6 billion in respect thereof, calculated by reference to the *Income Tax Act* (Canada) ("departure tax").

Hydro One Inc. also paid the Ontario Electricity Financial Corporation approximately $0.2 billion in additional payments in lieu of tax in connection with the initial public offering and approximately $0.1 billion in other payments in lieu of tax instalments.

For a discussion of the departure tax and the related financial implications on the Company, see the Annual MD&A under the heading "Related Party Transactions".

MATERIAL CONTRACTS

The following are the only material contracts, other than those contracts entered into in the ordinary course of business, which Hydro One Limited has entered into since the beginning of the last financial year, or entered into prior to such date but which contract is still in effect:

(a) the underwriting agreement (the "2016 Underwriting Agreement") dated April 7, 2016, between Hydro One Limited, the Province and a syndicate of underwriters pursuant to which the underwriters agreed to purchase, and the Province agreed to sell 72,434,800 common shares (such number of shares subsequently increased to an aggregate of 83,300,000 common shares) of Hydro One Limited at a price of $23.65 per share. The 2016 Underwriting Agreement provides that Hydro One Limited will indemnify the underwriters and each of their respective affiliates, and their directors, officers, partners, employees, agents and controlling persons against certain liabilities, including liabilities under Canadian securities legislation;

(b) the underwriting agreement (the "2015 Underwriting Agreement") dated October 29, 2015, between Hydro One Limited, Hydro One Inc., the Province and a syndicate of underwriters pursuant to which the underwriters agreed to purchase, and the Province agreed to sell 81,100,000 common shares (such number of shares subsequently increased to an aggregate of 89,250,000 common shares) of Hydro One Limited at a price of $20.50 per share. The 2015 Underwriting Agreement provides that Hydro One Limited and Hydro One Inc. will jointly and severally indemnify the underwriters and each of their respective affiliates, and their directors, officers, partners, employees, agents and controlling persons against certain liabilities, including liabilities under Canadian securities legislation;

(c) the Governance Agreement, described under “Agreements with Principal Shareholder”; and

(d) the Registration Rights Agreement, described under “Agreements with Principal Shareholder”.

Copies of the foregoing material agreements have been filed with the Canadian securities regulatory authorities and are available on SEDAR at www.sedar.com.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

The Company is from time to time involved in legal proceedings of a nature considered normal to its business. Except as disclosed below, Hydro One believes that none of the litigation in which it is currently involved, or has been involved since the beginning of the most recently completed financial year, individually or in the aggregate, is material to its consolidated financial condition or results of operations. The Company is not subject to any material regulatory actions.

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities Inc., and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. A certification motion in the class action is pending. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

In connection with the reorganization of Ontario Hydro, Hydro One Inc. succeeded Ontario Hydro as a party to various pending legal proceedings relating to the businesses, assets, real estate and employees transferred to it. Hydro One Inc. also assumed responsibility for future claims relating to the businesses, assets, real estate and employees acquired by Hydro One Inc. and arising out of events occurring prior to, as well as after, April 1, 1999. In addition to claims assumed by the Company, it is, from time to time, named as a defendant in legal actions arising in the normal course of business. There are currently no actions that are outstanding which are expected to have a material adverse effect on the Company.

INTEREST OF EXPERTS

KPMG LLP, Chartered Professional Accountants, located at 333 Bay Street, Suite 4600, Bay Adelaide Centre, Toronto, Ontario M5H 2S5, is the auditor of Hydro One Limited. and has audited the consolidated financial statements of Hydro One Limited as at and for the years ended December 31, 2016 and December 31, 2015. KPMG LLP has confirmed that it is independent of Hydro One Limited and Hydro One Inc. within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for Hydro One Limited’s common shares is Computershare Trust Company of Canada at its principal office in Toronto, Ontario.

ADDITIONAL INFORMATION

Additional information relating to Hydro One Limited may be found on SEDAR at www.sedar.com. Additional information, including with respect to directors' and officers' remuneration and indebtedness, principal holders of Hydro One Limited's securities and shares authorized for issuance under equity compensation plans, is contained in the Company's management information circular for its most recent annual meeting of shareholders that involves the election of directors.

Additional financial information is provided in the Annual MD&A and in the consolidated financial statements and notes to the consolidated financial statements of Hydro One Limited for 2016.

SCHEDULE "A"

HYDRO ONE LIMITED

AUDIT COMMITTEE MANDATE

Purpose

The Audit Committee (the "**Committee**") is a committee appointed by the board of directors (the "**Board**") of Hydro One Limited (including its subsidiaries, the "**Company**"). The Committee is established to fulfill applicable public company obligations and to assist the Board in fulfilling its oversight responsibilities with respect to financial reporting including responsibility to oversee:

(a) the independence, qualification and appointment of external auditors;

(b) the integrity of the Company's financial statements and financial reporting process, including the audit process and the Company's internal control over financial reporting, disclosure controls and procedures and compliance with other related legal and regulatory requirements;

(c) the performance of the Company's financial finance function, internal auditors and external auditors; and

(d) the auditing, accounting and financial reporting process.

The function of the Committee is oversight. It is not the duty or responsibility of the Committee or its members: (a) to plan or conduct audits; (b) to determine that the Company's financial statements are complete and accurate and are in accordance with generally accepted accounting principles; or (c) to conduct other types of auditing or accounting reviews or similar procedures or investigations. The Committee, its Chair and its members with accounting or finance expertise are members of the Board, appointed to the Committee to provide broad oversight of the financial, risk and control related activities of the Company, and are specifically not accountable or responsible for the day to day operation or performance of such activities.

Procedures

1. **Number of Members** – The members of the Committee shall be appointed by the Board. The Committee will be composed of not less than three (3) Board members.

2. **Independence** – The Committee shall be constituted at all times of directors who are "independent" (a) within the meaning of all Canadian securities laws and stock exchange requirements, each as in effect and applicable to Hydro One Limited from time to time; and (b) of the Province of Ontario within the meaning of the Governance Agreement between the Company and the Province of Ontario (as amended, revised or replaced from time to time, the "**Governance Agreement**").

3. **Financial Literacy** – Each member shall be "financially literate" within the meaning of other applicable requirements or guidelines for audit committee service under securities laws or the rules of any applicable stock exchange, including NI 52-110. At least one member will otherwise qualify as an "audit committee financial expert" as defined by applicable rules of the Securities and Exchange Commission.

4. **Cross-Appointment** – No member may serve on the audit committee of more than two other

public companies, unless the Board determined that this simultaneous service would not impair the ability of the member to serve effectively on the Committee.

5. **Appointment and Replacement of Committee Members** – Any member of the Committee may be removed or replaced at any time by the Board and shall automatically cease to be a member of the Committee upon ceasing to be a director. The Board shall fill any vacancy if the membership of the Committee is less than three directors. Whenever there is a vacancy on the Committee, the remaining members may exercise all its power as long as a quorum remains in office. Subject to the foregoing, the members of the Committee shall be appointed by the Board annually and each member of the Committee shall remain on the Committee until his or her successor shall be duly appointed and qualified or his or her earlier resignation or removal.

6. **Committee Chair** – Unless a Committee Chair is designated by the full Board, the members of the Committee may designate a Chair by majority vote of the full Committee. The Committee Chair shall be responsible for leadership of the Committee and reporting to the Board. If the Committee Chair is not present at any meeting of the Committee, one of the other members of the Committee who is present shall be chosen by the Committee to preside at the meeting. The Committee Chair shall also appoint a secretary who need not be a director.

7. **Conflicts of Interest** – If a Committee member faces a potential or actual conflict of interest relating to a matter before the Committee, other than matters relating to the compensation of directors, that member shall be responsible for alerting the Committee Chair. If the Committee Chair faces a potential or actual conflict of interest, the Committee Chair shall advise the Board Chair. If the Committee Chair, or the Board Chair, as the case may be, concurs that a potential or actual conflict of interest exists, the member faced with such conflict shall disclose to the Committee the member's interest and shall not be present for or participate in any discussion or other consideration of the matter and shall not vote on the matter.

8. **Meetings** – The Committee shall meet regularly and as often as it deems necessary to perform the duties and discharge its responsibilities as described herein in a timely manner, but not less than four (4) times a year. The Committee shall maintain written minutes of its meetings, which will be filed within the Company's corporate minute books. The Board Chair may attend and speak at all meetings of the Committee, whether or not the Board Chair is a member of the Committee.

9. **Separate Private Meetings** – The Committee shall meet regularly, but no less than quarterly, with the Chief Financial Officer, the head of the internal audit function (if other than the Chief Financial Officer) and the external auditors in separate private sessions to discuss any matters that the Committee or any of these groups believes should be discussed privately and such persons shall have access to the Committee to bring forward matters requiring its attention. The Committee shall also meet at each meeting of the Committee without management or non-independent directors present, unless otherwise determined by the Committee Chair.

10. **Professional Assistance** – The Committee may require the external auditors to perform such supplemental reviews or audits as the Committee may deem desirable and may retain such special legal, accounting, financial or other consultants as the Committee may determine to be necessary to carry out the Committee's duties, in each case at the Company's expense and inform the Chair of the Nominating and Corporate Governance Committee of any such retainer. The Company's external auditors will have direct access to the Committee at their own initiative.

11. **Reliance** – Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Committee shall be entitled to rely on: (a) the integrity of those persons or organizations within and outside the Company from which it receives information; (b) the accuracy of the financial and other information provided to the Committee by such

persons or organizations; and (c) representations made by management and the external auditors as to any information technology, internal audit and other permissible non-audit services provided by the external auditors to the Company and its subsidiaries.

12. **Reporting to the Board** – The Committee will report through the Committee Chair to the Board following meetings of the Committee on matters considered by the Committee, its activities and compliance with this Mandate.

Responsibilities

The principal responsibilities of the Committee are:

Selection and Oversight of the External Auditors

1. approve the terms of engagement and, if the shareholders authorize the Board to do so, the compensation to be paid by the Company to the external auditors with respect to the conduct of the annual audit. The external auditors are ultimately accountable to the Committee and the Board as the representatives of the shareholders of the Company and shall report directly to the Committee and the Committee shall so instruct the external auditors.

2. evaluate the quality of service, independence, objectivity, professional skepticism and performance of the external auditors and make recommendations to the Board on the reappointment or appointment of the external auditors of the Company to be proposed for shareholder approval and shall have authority to terminate the external auditors. If a change in external auditors is proposed by the Committee or management of the Company, the Committee shall review the reasons for the change and any other significant issues related to the change, including the response of the incumbent external auditors, and enquire on the qualifications of the proposed external auditors before making its recommendation to the Board.

3. review and approve policies and procedures for the pre-approval of services to be rendered by the external auditors. All permissible non-audit services to be provided to the Company or any of its affiliates by the external auditors or any of their affiliates that are not covered by pre-approval policies and procedures approved by the Committee shall be subject to pre-approval by the Committee. The Committee shall have the sole discretion regarding the prohibition of the external auditor providing certain non-audit services to the Company and its affiliates. The Committee shall also review and approve disclosures with respect to permissible non-audit services.

4. review the independence and professional skepticism of the external auditors and make recommendations to the Board on appropriate actions to be taken which the Committee deems necessary to protect and enhance the independence of the external auditors. In connection with such review, the Committee shall:

   (a) actively engage in a dialogue with the external auditors about all relationships or services that may impact the objectivity and independence of the external auditors, including whether there are any disputes, restrictions or limitations placed on their work;

   (b) obtain from external auditors at least annually, a formal written statement delineating all relationships between the Company and the external auditors and their affiliates;

   (c) ensure the rotation of the lead (and concurring) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by applicable law or professional practice; and

   (d) consider the auditor independence standards promulgated by applicable auditing regulatory and professional bodies.

5. review and approve policies for the hiring by the Company of employees or former employees of the external auditors.

6. require the external auditors to provide to the Committee, and review and discuss with the external auditors, all notices and reports which the external auditors are required to provide to the Committee or the Board under rules, policies or practices of professional or regulatory bodies applicable to the external auditors, and any other reports which the Committee may require. Such reports shall include:

(a) a description of the external auditors' internal quality-control procedures, any material issues respecting the external auditors raised by the most recent internal quality-control review, peer review or review body with auditing oversight responsibility over the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with any such issues; and

(b) a report describing: (i) the proposed audit plan and approach, (ii) all critical accounting policies and practices to be used by the Company; (iii) all alternative treatments of financial information within generally accepted accounting principles related to material items that have been discussed with management, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditors; and (iv) other material written communication between the external auditors and management, such as any management letter or schedule of unadjusted differences.

7. meet periodically with the external auditors to discuss their audit plan for the year, progress of their activities, any significant findings stemming from the external audit, any changes required in the planned scope of their audit plan, whether there are any disputes or any restrictions or limitations on the external auditors.

8. review the experience and qualifications of the audit team and review the performance of the external auditors, including assessing their effectiveness and quality of service, annually and, every five (5) years, perform a comprehensive review of the performance of the external auditors over multiple years to provide further insight on the audit firm, its independence and application of professional standards.

Appointment and Oversight of Internal Auditors

9. review and approve the appointment, terms of engagement, compensation, replacement or dismissal of the internal auditors. When the internal audit function is performed by employees of the Company, the Committee may delegate responsibility for approving the employment, terms of employment, compensation and termination of employees engaged in such function other than the head of the Company's internal audit function.

10. meet periodically with the internal auditors to review and approve their audit plan for the year, and discuss progress of their activities, any significant findings stemming from internal audits, any changes required in the planned scope of their audit plan and whether there are any disputes, restrictions or limitations on internal audit.

11. review summaries of the significant reports to management prepared by the internal auditors, or the actual reports if requested by the Committee, and management's responses to such reports.

12. communicate with, as it deems necessary, the internal auditors with respect to their reports and

recommendations, the extent to which prior recommendations have been implemented and any other matters that the internal auditor brings to the attention of the Committee. The head of the internal audit function shall have unrestricted access to the Committee.

13. evaluate, annually or more frequently as it deems necessary, the internal audit function, including its activities, organizational structure, independence and the qualifications, effectiveness and adequacy of the function.

Oversight and Review of Accounting Principles and Practices

14. review and discuss with management, the external auditors and the internal auditors (together and separately as it deems necessary), among other items and matters:

    (a) the quality, appropriateness and acceptability of the Company's accounting principles, practices and policies used in its financial reporting, its consistency from period to period, changes in the Company's accounting principles or practices and the application of particular accounting principles and disclosure practices by management to new transactions or events;

    (b) all significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including the effects of alternative methods within generally accepted accounting principles on the financial statements and any "second opinions" sought by management from an external auditor with respect to the accounting treatment of a particular item;

    (c) any material change to the Company's auditing and accounting principles and practices as recommended by management, the external auditors or the internal auditors or which may result from proposed changes to applicable generally accepted accounting principles;

    (d) the extent to which any changes or improvements in accounting or financial practices, as approved by the Committee, have been implemented;

    (e) any reserves, accruals, provisions or estimates that may have a material effect upon the financial statements of the Company;

    (f) the use of any "pro forma" or "adjusted" information which is not in accordance with generally accepted accounting principles;

    (g) the effect of regulatory and accounting initiatives on the Company's financial statements and other financial disclosures; and

    (h) legal matters, claims and contingencies that could have a significant impact on the Company's financial statements.

15. review and resolve disagreements between management and the external auditors regarding financial reporting or the application of any accounting principles or practices.

Oversight and Monitoring of Internal Controls

16. exercise oversight of, review and discuss with management, the external auditors and the internal auditors (together and separately), as it deems necessary:

    (a) the adequacy and effectiveness of the Company's internal control over financial reporting and disclosure controls and procedures designed to ensure compliance with applicable laws and regulations;

(b) any significant deficiencies or material weaknesses in internal control over financial reporting or disclosure controls and procedures, and the status of any plans for their remediation;

(c) the adequacy of the Company's internal controls and any related significant findings and recommendations of the external auditors and internal auditors together with management's responses thereto; and

(d) management's compliance with the Company's processes, procedures and internal controls.

Oversight and Monitoring of the Company's Financial Reporting and Disclosures

17. review with the external auditors and management and recommend to the Board for approval the audited annual financial statements and unaudited interim financial statements, and the notes and Management's Discussion and Analysis accompanying all such financial statements, the Company's annual report and any other disclosure documents or regulatory filings containing or accompanying financial information of the Company, prior to the release of any summary of the financial results or the filing of such reports with applicable regulators.

18. discuss earnings press releases prior to their distribution, as well as financial information and earnings guidance prior to public disclosure, it being understood that such discussions may, in the discretion of the Committee, be done generally (i.e., by discussing the types of information to be disclosed and the type of presentation to be made) and that the Committee need not discuss in advance each earnings release or each instance in which the Company gives earning guidance.

19. review with management the Company's disclosure controls and procedures and material changes to the design of the Company's disclosure controls and procedures.

20. receive and review the financial statements and other financial information of material subsidiaries of the Company and any auditor recommendations concerning such subsidiaries.

21. meet with management to review the adequacy of the process and systems in place for ensuring the reliability of public disclosure documents that contain audited and unaudited financial information.

Oversight of Finance Matters

22. periodically review matters pertaining to the Company's material policies and practices respecting cash management and material financing strategies or policies or proposed financing arrangements and objectives of the Company.

23. periodically review the Company's major financial risk exposures (including foreign exchange and interest rate) and management's initiatives to control such exposures, including the use of financial derivatives and hedging activities.

24. review and discuss with management all material off-balance sheet transactions, arrangements, obligations (including contingent obligations), leases and other relationships of the Company with unconsolidated entities or other persons, that may have a material current or future effect on financial condition, changes in financial condition, results of operations, liquidity, capital resources, capital reserves, or significant components of revenues or expenses.

25. review and discuss with management any equity investments, acquisitions and divestitures that may have a material current or future effect on financial condition, changes in financial condition, results of operations, liquidity, capital resources, capital reserves, or significant components of

revenues or expenses.

26. review and discuss with management the Company's effective tax rate, adequacy of tax reserves, tax payments and reporting of any pending tax audits or assessments, and material tax policies and tax planning initiatives.

27. review the organizational structure of the finance function and satisfy itself as to the qualifications, effectiveness and adequacy of the function.

28. review the work plan and progress on implementation of major information technology system changes and satisfy itself as to the adequacy of the information system infrastructure.

Regulatory Matters

29. review the financial impact to the Company of electrical regulatory initiatives.

30. review the financial implications of Company initiatives which may have a material impact on transmission and distribution rate filing applications.

Code of Business Conduct and Whistleblower Policy

31. review and recommend to the Board for approval any changes to the Code of Business Conduct for employees, officers and directors of the Company.

32. review and approve changes to the whistleblower policy or other procedures for: (a) the receipt, retention, and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and (b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

33. oversee management's monitoring of, compliance with the Company's Code of Business Conduct and the Whistleblower Policy.

Enterprise Risk Management

34. review the Enterprise Risk Management framework for the Company and assess the adequacy and completeness of the process for identifying and assessing the key risks facing the Company.

35. meet with the head of the Enterprise Risk Management function at least semi-annually.

36. ensure that primary oversight responsibility for each of the key risks identified in the Enterprise Risk Management framework is assigned to the Board or one of its Committees.

Additional Responsibilities

37. review the Company's privacy and data security risk exposures and measures taken to protect the security and integrity of its management information systems and Company and customer data.

38. review and approve in advance any proposed related-party transactions and required disclosures of such in accordance with applicable securities laws and regulations and consistent with the Company's related party transaction policy, and report to the Board on any approved transactions.

39. review on an annual basis reports on the expense accounts of the Chief Executive Officer and his or her direct reports.

40. undertake on behalf of the Board such other initiatives as may be necessary or desirable to assist the Board in fulfilling its oversight responsibilities with respect to financial reporting and perform such other functions as required by law, stock exchange rules or the Company's constating

documents.

41. review annually the adequacy of this Mandate and ensure that it is disclosed in compliance with applicable securities laws and stock exchange rules and posted on the Company's website.