

ALGONQUIN

Q1 2017



ALGONQUIN
Power & Utilities Corp.



ALGONQUIN POWER & UTILITIES CORP.

UNDENIABLE STRENGTH: Algonquin Power & Utilities Corp. is a North American diversified generation, transmission and distribution utility with more than \$10 billion of total assets.

CLEAR VISION: To be the utility company most admired by customers, communities and investors for its people, passion and performance.



ALGONQUINPOWERANDUTILITIES.COM

TORONTO STOCK EXCHANGE: **AQN**

NEW YORK STOCK EXCHANGE: **AQN**

Management's Discussion & Analysis

(All monetary amounts are in thousands of Canadian dollars, except per share amounts or where otherwise noted.)

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three months ended March 31, 2017. The Management's Discussion & Analysis ("MD&A") should be read in conjunction with APUC's Unaudited Interim Consolidated Financial Statements for the three months ended March 31, 2017 and 2016. The MD&A should also be read in conjunction with APUC's Annual Audited Consolidated Financial Statements for the years ended December 31, 2016 and 2015, and the annual MD&A for the year ended December 31, 2016. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of May 11, 2017.

Caution Concerning Forward-looking Statements, Forward-looking Information and non-GAAP Measures

Forward-looking Statements and Forward-looking Information

This MD&A may contain statements that, to the extent that they are not recitations of historical fact, constitute "forward-looking statements" or "forward-looking information" and within the meaning of applicable securities legislation, including the *United States Securities Act of 1933*, as amended, the *United States Securities Exchange Act of 1934*, as amended, and applicable Canadian Securities legislation (collectively referred to herein as "forward-looking information" or "forward-looking statements"). All forward-looking information and forward-looking statements are given pursuant to the "safe harbour" provisions of applicable securities legislation. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets as well as the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward-looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require APUC to make assumptions and involve inherent risks and uncertainties. APUC cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; and the state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements. In addition, such statements are made based on information available and expectations as of the date of this MD&A and such expectations may change after this date. APUC reviews material forward-looking information it has presented, not less frequently than on a quarterly basis. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

Non-GAAP Financial Measures

The terms "Adjusted Net Earnings", "Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization" ("Adjusted EBITDA"), "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are used throughout this MD&A. The terms "Adjusted Net Earnings", "Adjusted Funds from Operations", "Adjusted EBITDA", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are not recognized measures under GAAP. There is no standardized measure of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit"; consequently, APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit" can be found throughout this MD&A.

Use of Non-GAAP Financial Measures

Adjusted EBITDA

EBITDA is a non-GAAP measure used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of (as applicable): depreciation and amortization expense, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the Company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

Adjusted Net Earnings

Adjusted Net Earnings is a non-GAAP measure used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Net Earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP, which can be impacted positively or negatively by these items.

Adjusted Funds from Operations

Adjusted Funds from Operations is a non-GAAP measure used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Funds from Operations to assess its performance without the effects of (as applicable): changes in working capital balances, acquisition expenses, litigation expenses, cash provided by or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP, which can be impacted positively or negatively by these items.

Net Energy Sales

Net Energy Sales is a non-GAAP measure used by investors to identify revenue after commodity costs used to generate revenue where such revenue generally increases or decreases in response to increases or decreases in the cost of the commodity used to produce that revenue. APUC uses Net Energy Sales to assess its revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through either directly or indirectly in the rates that are charged to customers. APUC believes that analysis and presentation of Net Energy Sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Net Utility Sales

Net Utility Sales is a non-GAAP measure used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodity costs are generally included as a pass through in rates to its utility customers. APUC uses Net Utility Sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by utility customers. APUC believes that analysis and presentation of Net Utility Sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Divisional Operating Profit

Divisional Operating Profit is a non-GAAP measure. APUC uses Divisional Operating Profit to assess the operating performance of its business groups without the effects of (as applicable): depreciation and amortization expense, corporate administrative expenses, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they

may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the divisional units. Divisional Operating Profit is calculated inclusive of Hypothetical Liquidation at Book Value ("HLBV") income, which represents the value of net tax attributes earned in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's divisional operating performance. Divisional Operating Profit is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

Capitalized terms used herein and not otherwise defined will have the meanings assigned to them in the Company's most recent AIF.

Overview and Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets which deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through real per share growth in earnings and cash flows to support a growing dividend and share price appreciation.

APUC's current quarterly dividend to shareholders is U.S. \$0.1165 per common share or U.S. \$0.4659 per common share per annum. Based on the Bank of Canada's daily exchange rate as at May 10, 2017, the quarterly dividend is equivalent to Cdn \$0.1593 per common share or Cdn \$0.6371 per common share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities. Further increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board"), with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC's operations are organized across two primary North American business units consisting of: the Liberty Power Group which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; and the Liberty Utilities Group which owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations.

Liberty Power Group

The Liberty Power Group generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean energy power generation facilities located across North America. The Liberty Power Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

The Liberty Power Group owns or has interests in hydroelectric, wind, solar, and thermal facilities with a combined generating capacity of approximately 120 MW, 1,050 MW, 40 MWac, and 335 MW, respectively. Approximately 88% of the electrical output from the hydroelectric, wind, and solar generating facilities is sold pursuant to long term contractual arrangements which have a production-weighted average remaining contract life of 16 years.

The Liberty Power Group also has a portfolio of development projects that when constructed will add approximately 351 MW of generation capacity from wind and solar powered generating facilities that have a production-weighted average contract life of 22 years.

Liberty Utilities Group

The Liberty Utilities Group operates a diversified portfolio of regulated utility systems throughout the United States. Liberty Utilities provides safe, high quality, and reliable services to its customers and delivers stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities delivers continued growth in earnings through accretive acquisition of additional utility systems.

On January 1, 2017, Liberty Utilities Co., APUC's wholly-owned regulated utility business, completed the acquisition of The Empire District Electric Company ("Empire"). Empire is a vertically-integrated utility providing electric, natural gas and water service to approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas.

Including Empire, the Liberty Utilities Group now serves approximately 780,000 customers.

The Liberty Utilities Group's regulated electrical distribution utility systems and related generation assets are located in the States of California, New Hampshire, Missouri, Kansas, Oklahoma and Arkansas. The electric utility systems in total serve approximately 263,000 electric connections and operate a fleet of generation assets with a net capacity of 1,424 MW.

The Liberty Utilities Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, New Hampshire and Missouri serving approximately 335,000 natural gas connections.

The Liberty Utilities Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, California, Illinois, Missouri, Montana, and Texas which together serve approximately 182,000 connections.

2017 Major Highlights

Corporate Highlights

Completion of The Empire District Electric Company Acquisition

On January 1, 2017, APUC's wholly-owned regulated utility business successfully completed its acquisition of Empire for an aggregate purchase price of approximately U.S. \$2.414 billion ("Empire Acquisition").

Empire is a Joplin, Missouri based regulated electric, gas and water utility that serves approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas.

With the closing of the Empire Acquisition, APUC has materially expanded its utility operations in the U.S.. APUC, through its 2,200 employees, now serves over 780,000 electric, gas, and water customers within its regulated utility business, and APUC's portfolio of power generating facilities now contains both regulated and non-regulated power facilities with a total generating capacity of over 2,500 MW.

Accretion of Empire in First Quarter Operating Results

APUC recorded a strong three months of operations results relative to the same period last year primarily as a result of the acquisition of Empire.

(all dollar amounts in \$ millions except per share information)	Three Months Ended March 31		
	2017	2016	Change
Net earnings attributable to shareholders ¹	\$ 26.0	\$ 42.0	(38)%
Adjusted Net Earnings	\$ 88.1	\$ 56.1	57 %
Adjusted EBITDA	\$ 254.8	\$ 147.9	72 %
Net earnings per common share	\$ 0.07	\$ 0.15	(53)%
Adjusted Net Earnings per common share	\$ 0.25	\$ 0.21	19 %

¹ Includes \$60.4 million of Acquisition Related Costs expensed in the first quarter of 2017 as compared to \$6.3 million in 2016

Completion of Financing Related to the Acquisition of Empire

\$1.15 Billion Bought Deal Offering of Convertible Unsecured Subordinated Debentures Represented by Instalment Receipts

In the first quarter of 2016, in connection with the Acquisition, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, \$1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("Debentures") of APUC (the "Debenture Offering").

Following the closing of the Acquisition, the final instalment date was established as February 2, 2017 at which time APUC received the final instalment payment. As at May 10, 2017, approximately 99.6% representing \$1.146 billion of the Debentures have been converted into 108,075,037 common shares of APUC. The proceeds were used to repay a portion of APUC's bank facility drawn at closing of the Acquisition ("Acquisition Facility").

U.S. \$750 Million Private Placement Offering

On March 24, 2017, Liberty Utilities through its financing entity issued U.S. \$750.0 million of senior unsecured private placement notes to 29 institutional investors in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and an effective interest rate of 3.6% (inclusive of interest rate hedges).

Annual dividend increased from U.S. \$0.4235 to U.S. \$0.4659 and

Declaration of Canadian Equivalent Second Quarter Dividend of Cdn \$0.1593 (U.S. \$0.1165) per Common Share

APUC currently targets 10% annual growth in dividends payable to shareholders underpinned by increases in earnings and cashflow. Management believes that the increase in dividends is consistent with APUC's stated strategy of delivering total shareholder return comprised of an attractive current dividend yield and capital appreciation.

In addition to the completion of the Empire Acquisition in the first quarter of 2017, APUC completed construction of new electric generating stations and has a number of electric generating stations in construction and under development. Collectively these growth initiatives have continued to raise the growth profile of the Company. As a result, on January 16, 2017, the Board approved a dividend increase of U.S. \$0.0424 per common share annually, bringing the total annual dividend to U.S. \$0.4659 per common share, an increase of 10% over the previous annual dividend rate.

The previous four quarter equivalent Canadian dollar dividends per common share have been as follows:

	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Total
U.S. dollar dividend	\$0.1059	\$0.1059	\$0.1165	\$0.1165	\$0.4448
Canadian dollar equivalent	\$0.1377	\$0.1427	\$0.1533	\$0.1593	\$0.5930

Liberty Power Group Highlights

Completion of the Deerfield Wind Project

On February 21, 2017, the Deerfield Wind Facility achieved commercial operations ("COD"). The project consists of a 150 MW wind generating facility located in central Michigan. On May 10, 2017, tax equity financing of approximately U.S. \$166.6 million was completed. The Deerfield Wind Facility is the Liberty Power Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs annually. The project has a 20 year Power Purchase Agreement ("PPA") with an investment grade local electric distribution utility serving approximately 260,000 customers in Michigan.

Completion of the Bakersfield II Solar Project

On January 11, 2017, the Liberty Power Group achieved COD on the 10 MWac solar generating facility located in Kern County, California (the "Bakersfield II Solar Facility"). On February 28, 2017, tax equity financing of approximately U.S. \$12.3 million was completed. The Bakersfield II Solar Facility is the Liberty Power Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy annually. The project has a 20 year PPA with a large investment grade electric utility in California.

Issuance of \$300 million Senior Unsecured Debentures

On January 17, 2017 the Liberty Power Group issued \$300.0 million of senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of \$99.929 per \$100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars.

The net proceeds were used to partially finance the Odell Wind, Deerfield Wind and Bakersfield II Solar projects.

Liberty Utilities Group Highlights

Completion of the Luning Solar Project.

On February 15, 2017, the Liberty Utilities Group obtained control of a 50 MWac solar generating facility located in Mineral County, Nevada for approximately U.S. \$110.9 million. The facility is comprised of approximately 204,784 solar panels located on 584 acres of land. The project is expected to generate 144.6 GW-hrs of energy annually. On February 17, 2017, tax equity financing of approximately U.S. \$39.0 million was completed. The net capital cost of the project will be included in the rate base of the CalPeco Electric System as energy produced from the project will be consumed by the utility's customers.

Key Financial Information

- ¹ Non-GAAP Financial Measures.
- ² APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.
- ³ Includes current and long-term portion of debt and convertible debentures per the financial statements.

For the three months ended March 31, 2017, APUC experienced an average U.S. exchange rate of approximately 1.3229 as compared to 1.3741 in the same period in 2016. As such, any quarter-over-quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the three months ended March 31, 2017, APUC reported total revenue of \$557.9 million as compared to \$341.7 million during the same period in 2016, an increase of \$216.2 million. The major factors resulting in the increase in APUC revenue in the three months ended March 31, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in \$ millions)

Three Months Ended
March 31

Comparative Prior Period Revenue	\$	341.7
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Decrease is primarily due to the recognition of the global adjustment from the Ontario Energy Finance Corporation ("OEFC") in 2016 as well as decreased production, partially offset by annual PPA rate increases.		(1.9)
Wind Canada: Increase is largely due to increased production and annual rate increases.		0.5
Wind U.S.: Decrease is primarily due to fewer REC sales as compared to the prior year.		(1.1)
Solar U.S.: Decrease is primarily due to business interruption insurance proceeds received in the prior year in excess of current year production.		(0.5)
Thermal: Increase was due to higher fuel prices realized at the Windsor Lock Thermal Facility and rising REC prices, partially offset by the decrease in production at Sanger.		0.8
Other: Decrease was primarily caused by the shutdown of the hydro mulch business at Sanger.		(0.7)
		(2.9)
New Facilities		
Wind U.S.: Acquisition of Odell (Sept 2016) and Deerfield (Feb 2017) Wind facilities.		8.6
Solar U.S.: Bakersfield II was placed in service in Dec 2016.		0.3
		8.9
Foreign Exchange		(1.7)
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease was primarily due to lower commodity pass-through costs at the Granite State and CalPeco Electric Systems.		(7.8)
Gas: Increase was primarily due to increased pass-through costs at the EnergyNorth and New England Gas systems as it relates to higher customer demand, partially offset by warmer weather in the Midstates Gas System.		14.5
Water: Increase is primarily due to increased usage at the Park Water System.		0.8
Other		0.3
		7.8
New Facilities		
Electricity: Acquisition of Empire's electric distribution systems on January 1, 2017.		181.9
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		18.2
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.7
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		2.5
		203.3
Rate Cases		
Electricity: Implementation of new rates at the CalPeco Electric system and interim rates at the Granite State Electric system.		5.1
Gas: Implementation of new rates at the Peach State, Missouri, Iowa and New England Gas systems.		6.2
Water: Implementation of new rates at the Rio Rico and Bella Vista water systems.		0.5
		11.8
Foreign Exchange		(11.0)
Current Period Revenue	\$	557.9

A more detailed discussion of these factors is presented within the business unit analysis.

For the three months ended March 31, 2017, net earnings attributable to shareholders totaled \$26.0 million as compared to \$42.0 million during the same period in 2016, a decrease of \$16.0 million or 38.1%. The decrease was primarily due to a \$54.1 million increase in acquisition related costs due to the acquisition of Empire as compared to the same period in 2016. Other factors affecting changes to net earnings were a \$3.2 million increase in administration charges, \$33.0 million increase in depreciation and amortization expenses, \$39.5 million increase in interest expense, \$1.2 million decrease in other

gains, \$0.4 million decrease in foreign exchange gain, \$0.9 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*), and \$0.5 million increase in losses from derivative instruments. These items were partially offset by a \$101.1 million increase in earnings from operating facilities (including Empire), \$0.7 million increase in interest, dividend, equity and other income, \$8.8 million increase in losses attributable to non-controlling interests, and a \$6.2 million decrease in losses on long lived assets.

During the three months ended March 31, 2017, cash provided by operating activities totaled \$83.8 million as compared to cash provided by operating activities of \$53.4 million during the same period in 2016. During the three months ended March 31, 2017, Adjusted Funds from Operations totaled \$208.9 million compared to Adjusted Funds from Operations of \$121.8 million during the same period in 2016. The change in Adjusted Funds from Operations in the three months ended March 31, 2017 is primarily due to increased earnings from operations (including Empire) as compared to the same period in 2016.

During the three months ended March 31, 2017 Adjusted EBITDA totaled \$254.8 million as compared to \$147.9 million during the same period in 2016, an increase of \$106.9 million or 72.3%. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Performance Measures*).

2017 Adjusted EBITDA Summary

Adjusted EBITDA in the three months ended March 31, 2017 totaled \$254.8 million as compared to \$147.9 million during the same period in 2016, an increase of 106.9 million or 72.3%. The breakdown of Adjusted EBITDA (see *Non-GAAP Performance Measures*) by the company's main operating segments and summaries of changes is shown below.

Adjusted EBITDA by segment (all dollar amounts in \$ millions)	Three Months Ended March 31	
	2017	2016
Liberty Power Group Operating Profit	\$ 70.1	\$ 63.4
Liberty Utilities Group Operating Profit	198.6	95.1
Administration Expenses	(14.6)	(11.4)
Other Income & Expenses	0.7	0.8
Total Algonquin Power & Utilities Adjusted EBITDA	\$ 254.8	\$ 147.9
Change in Adjusted EBITDA (\$)	\$ 106.9	
Change in Adjusted EBITDA (%)	72.3%	

Change in Adjusted EBITDA Breakdown

(all dollar amounts in \$ millions)	Liberty Power	Liberty Utilities	Corporate	Total
Prior Period Balances	\$ 63.4	\$ 95.1	\$ (10.6)	\$ 147.9
Existing Facilities	(2.9)	6.0	(0.1)	3.0
New Facilities	10.6	89.3	—	99.9
Rate Cases	—	11.8	—	11.8
Foreign Exchange Impact	(1.0)	(3.6)	—	(4.6)
Administration Expenses	—	—	(3.2)	(3.2)
Total change during the period	\$ 6.7	\$ 103.5	\$ (3.3)	\$ 106.9
Current Period Balances	\$ 70.1	\$ 198.6	\$ (13.9)	\$ 254.8

LIBERTY POWER GROUP

2017 Electricity Generation Performance

	Long Term Average Resource	Three Months Ended March 31	
(Performance in GW-hrs sold)		2017	2016
Hydro Facilities:			
Maritime Region	27.5	34.4	47.7
Quebec Region	56.0	61.6	73.8
Ontario Region	36.0	35.0	40.3
Western Region	9.6	10.2	10.8
	129.1	141.2	172.6
Wind Facilities:			
St. Damase	20.9	21.0	22.5
St. Leon	121.4	113.1	91.0
Red Lily ¹	23.2	23.7	18.5
Morse	30.5	25.4	21.9
Sandy Ridge	47.1	50.8	49.1
Minonk	200.6	206.4	209.4
Senate	151.3	148.4	153.4
Shady Oaks	108.2	110.5	97.6
Odell ²	230.5	231.3	—
Deerfield ³	75.8	73.7	—
	1,009.5	1,004.3	663.4
Solar Facilities:			
Cornwall	2.6	2.5	2.5
Bakersfield I	9.1	8.7	7.9
Bakersfield II ⁴	3.8	3.9	—
	15.5	15.1	10.4
Renewable Energy Performance	1,154.1	1,160.6	846.4
Thermal Facilities:			
Windsor Locks	N/A ⁵	30.0	28.2
Sanger	N/A ⁵	15.1	32.0
		45.1	60.2
Total Performance		1,205.7	906.6

¹ Effective April 12, 2016, APUC, through its subsidiary, exercised its option and acquired a 75% equity interest in the Red Lily Wind Facility. For financial accounting purposes, APUC's majority interest in the Red Lily Wind Facility is accounted for using the equity method. The production figures represent full energy produced by the facility.

² The Odell Wind Facility achieved COD on July 29, 2016 and was treated as an equity investment until September 15, 2016 at which time the Company acquired the remaining 50% ownership in the facility.

³ The Deerfield Wind Facility achieved COD on February 21, 2017 and was treated as an equity investment until March 14, 2017 at which time the Company acquired the remaining 50% ownership in the facility. The LTAR and production noted above represents all production from the date of COD.

⁴ The Bakersfield II Solar Facility achieved COD on January 11, 2017 in accordance with the terms of the PPA. The LTAR and production noted above represents all production from the date of COD.

⁵ Natural gas fired co-generation facility.

2017 First Quarter Liberty Power Performance

For the three months ended March 31, 2017, the Liberty Power Group generated 1,205.7 GW-hrs of electricity as compared to 906.6 GW-hrs during the same period of 2016.

For the three months ended March 31, 2017, the hydro facilities generated 141.2 GW-hrs of electricity as compared to 172.6 GW-hrs produced in the same period in 2016, a decrease of 18.2%. Electricity generated represented 109.4% of long-term average resources ("LTAR") as compared to 131.4% during the same period in 2016. During the quarter, generation in the Maritime, Quebec and Western regions surpassed their respective LTARs.

For the three months ended March 31, 2017, the wind facilities produced 1,004.3 GW-hrs of electricity as compared to 663.4 GW-hrs produced in the same period in 2016, an increase of 51.4%. The higher generation was primarily due to the first full quarter of production at the Odell Wind Facility (which achieved COD on July 29, 2016) as well as generation from the new Deerfield Wind Facility. These items were partly offset by lower production at the St. Damase, Minonk and Senate Wind Facilities. During the three months ended March 31, 2017, the wind facilities (excluding the Odell Wind Facility) generated electricity equal to 99.4% of LTAR as compared to 98.5% during the same period in 2016.

For the three months ended March 31, 2017, the solar facilities generated 15.1 GW-hrs of electricity as compared to 10.4 GW-hrs of electricity in the same period in 2016, an increase of 45.2%. The increase in production is largely attributable to the new Bakersfield II Solar Facility. Excluding the new site, Cornwall and Bakersfield had a production increase of 7.7%.

For the three months ended March 31, 2017, the thermal facilities generated 45.1 GW-hrs of electricity as compared to 60.2 GW-hrs of electricity during the same period in 2016. During the same period, the Windsor Locks Thermal Facility generated 166.5 billion lbs of steam as compared to 185.7 billion lbs of steam during the same period in 2016.

2017 Liberty Power Group Operating Results

(all dollar amounts in \$ millions)	Three Months Ended March 31	
	2017	2016
Revenue ¹		
Hydro	\$ 17.5	\$ 19.7
Wind	44.1	35.7
Solar	2.2	2.4
Thermal	8.0	7.7
Total Revenue	\$ 71.8	\$ 65.5
Less:		
Cost of Sales - Energy ²	(1.7)	(1.1)
Cost of Sales - Thermal	(5.6)	(4.5)
Realized loss on hedges ³	(0.7)	(1.0)
Net Energy Sales	\$ 63.8	\$ 58.9
Renewable Energy Credits ("REC")	4.8	6.1
Other Revenue	0.1	0.8
Total Net Revenue	\$ 68.7	\$ 65.8
Expenses & Other Income		
Operating expenses	(19.2)	(16.3)
Interest, dividend, equity and other income	1.2	0.5
HLBV income ⁴	19.4	13.4
Divisional Operating Profit⁵	\$ 70.1	\$ 63.4

¹ While most of the Liberty Power Group's PPAs include annual rate increases, a change to the weighted average production levels resulting from higher average production from facilities that earn lower or higher energy rates can result in a different weighted average energy rate earned by the division as compared to the same period in the prior year.

² Cost of Sales - Energy consists of energy purchases in the Maritime Region to manage the energy sales from the Tinker Hydro Facility which is sold to retail and industrial customers under multi-year contracts.

³ See financial statements note 21(b)(iv).

⁴ HLBV income represents the value of net tax attributes earned by the Liberty Power Group in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities.

⁵ See Non-GAAP Financial Measures.

2017 First Quarter Operating Results

For the three months ended March 31, 2017, the Liberty Power Group facilities generated \$70.1 million of operating profit as compared to \$63.4 million during the same period in 2016, which represents an increase of \$6.7 million, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in \$ millions)		Three Months Ended March 31
Prior Period Operating Profit	\$	63.4
Existing Facilities		
Hydro: Decrease largely due to prior year recognition of Global Adjustment payment from the Ontario Energy Finance ("OEF") in 2016 as well as a decline in production compared to the previous year. In the Maritime region the decreased production necessitated an increase in purchased power to supply retail customers.		(2.2)
Wind Canada: Increase is largely due to increased production and annual rate increases.		0.4
Wind U.S.: Increase is primarily due to higher production at the Shady Oaks Wind Facility, and HLBV income, partially offset by lower REC revenues.		0.7
Solar U.S.: Decrease is primarily due to business interruption insurance proceeds received in the prior year in excess of current year operating profit.		(0.5)
Thermal: Decrease is primarily due to higher commodity costs at the thermal facilities, partially offset by higher REC sales at the Windsor Locks Thermal Facility.		(0.3)
Other: Decrease was primarily due to the permanent shutdown of the hydro mulch business at the Sanger Thermal Facility.		(1.0)
		(2.9)
New Facilities		
Wind U.S.: Acquisition of Odell and Deerfield Wind facilities.		10.3
Solar U.S.: Bakersfield II was placed in service in Dec 2016.		0.3
		10.6
Foreign Exchange		(1.0)
Current Period Divisional Operating Profit	\$	70.1

Development Division

The Liberty Power Group's Development Division is focused on developing, contracting, and transitioning recently completed projects to the operations group. The division has successfully advanced a number of projects and has been awarded or acquired a number of PPAs. All of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with credit-worthy counterparties, and satisfy the Company's investment return objectives. The projects are as follows:

Project Name	Location	Size (MW)	Estimated Capital Cost (millions) ³	Commercial Operation	PPA Term	Production GW-hrs
Projects in Construction						
Amherst Island Wind Project	Ontario	75	\$ 295	2018	20	235
Great Bay Solar Project ¹	Maryland	75	193	2017	10	146
Total Projects in Construction		150	\$ 488			381
Projects in Development						
Blue Hill Wind Project	Saskatchewan	177	\$ 345	2019/20	25	813
Val-Eo Wind Project ²	Quebec	24	65	2018	20	66
Total Projects in Development		201	\$ 410			879
Total in Construction and Development		351	\$ 898			1,260

¹ The total cost of the project is expected to be approximately \$145 million in U.S. dollars.

² All figures refer solely to Phase I of the Val-Eo Wind Project.

³ Estimated capital costs for U.S. based projects have been converted at the exchange rate in effect at the end of the current reporting period.

Projects Recently Completed

Deerfield Wind Project

The Deerfield Wind Project is a 150 MW wind powered electric generating project located in central Michigan with land control over approximately 20,000 acres of land.

Construction of the project commenced in the fourth quarter of 2015. The project declared commercial operations on February 21, 2017.

The project is the Liberty Power Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs of energy per year, with all energy, capacity, and renewable energy credits from the project sold to Wolverine Power Supply Cooperative, a local electric distribution utility, which serves 260,000 customers in Michigan, pursuant to a 20 year PPA. The facility achieved COD on February 21, 2017.

The Liberty Power Group's initial interest in the project was via a 50% joint venture with the original developer along with an option to acquire the other 50% interest. On March 14, 2017, the Liberty Power Group exercised its option and purchased the remaining 50% interest in the project for U.S. \$21.6 million.

The project qualifies for U.S. federal production tax credits, and consistent with financing structures utilized for U.S. based renewable energy projects approximately U.S. \$166.6 million of financing for the project was sourced from tax equity investors.

Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MWac solar powered electric generating project adjacent to the Liberty Power Group's 20 MWac Bakersfield I Solar Project in Kern County, California.

Construction of the project commenced in the second quarter of 2015. The facility declared commercial operations on January 11, 2017.

The facility is the Liberty Power Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.

The project qualifies for U.S. federal investment tax credits, and consistent with financing structures utilized for U.S. based renewable energy projects approximately U.S. \$12.3 million of financing for the project was sourced from tax equity investors. The tax equity financing closed on February 28, 2017 following achievement of commercial operations.

Projects in Construction

Amherst Island Wind Project

The Amherst Island Wind Project is a 75 MW wind powered electric generating development project located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario.

The Renewable Energy Approval ("REA") for the project was issued on August 24, 2015 following 29 months of review by the Ontario Ministry of Environment. An appeal of the REA was made to the Environmental Review Tribunal ("ERT") in 2015. The ERT decision to uphold the REA was issued on August 3, 2016. A Divisional Court challenge of the favorable ERT decision was dismissed in the first quarter of 2017.

Construction is underway and progressing according to schedule. The Company has procured the project turbines, submarine cable, and the main power transformer. The balance of plant constructor has also been engaged. Subject to receipt of final permits and negotiation of remaining agreements, construction is expected to be complete in the second quarter of 2018.

Great Bay Solar

The Great Bay Solar Project is a 75 MWac solar powered electric generating development project located in Somerset County in southern Maryland.

The facility is composed of 300,000 solar panels and is being constructed on 400 acres of land. The project is expected to generate 146.0 GW-hrs of energy per year, with all energy sold to the U.S. Government Services pursuant to a 10 year PPA, with a 10 year extension option. All solar renewable energy credits from the project will be retained by the project company and sold into the Maryland market.

The project has received its Certificate of Public Convenience and Necessity from the State of Maryland Public Service Commission and building permits from the Somerset County Building and Zoning Department. Both the balance of plant and high voltage engineering, procurement, and construction contracts have been executed, and project construction has commenced. The project has a commercial operations date targeted for the end of 2017.

The total costs to complete the project are estimated at approximately U.S. \$145.0 million. The Liberty Power Group expects the project will qualify for U.S. federal investment tax credits and accordingly, has selected a tax equity investor to provide approximately 40% of the permanent project financing in return for the majority of the tax attributes.

Projects in Development

Blue Hill Wind Project

The Blue Hill Wind Project is a 177 MW wind powered electric generating development project located in the rural municipality of Lawtonia in southwest Saskatchewan. All of the energy from the project will be sold to SaskPower pursuant to a 25 year PPA originally awarded in 2012. The project requires final environmental approval and all other necessary permitting. SaskPower is currently completing a system impact study for the wind turbine generators, and environmental field studies are in progress.

LIBERTY UTILITIES GROUP

The Liberty Utilities Group operates rate-regulated utilities that provide distribution services to approximately 780,000 connections in the natural gas, electric, water and wastewater sectors. On January 1, 2017, Liberty Utilities completed the acquisition of Empire. Empire is a vertically-integrated utility providing electric, natural gas and water service serving approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas. The Liberty Utilities Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Liberty Utilities Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing connections in the communities in which it operates.

Utility System Type

	As at March 31			
	2017		2016	
(all dollar amounts in U.S. \$ millions)	Assets	Total Connections ¹	Assets	Total Connections ¹
Electricity	\$ 2,471.1	263,000	\$ 346.0	93,000
Natural Gas	917.5	335,000	784.5	293,000
Water and Wastewater	525.8	182,000	498.1	178,000
Total	\$ 3,914.4	780,000	\$ 1,628.6	564,000
Accumulated Deferred Income Taxes Liability	\$ 639.1		\$ 167.3	

¹ Total Connections represents the sum of all active and vacant connections.

The Liberty Utilities Group aggregates the performance of its utility operations by utility system type – electricity, natural gas, and water and wastewater systems.

The electric distribution systems are comprised of regulated electrical distribution utility systems and serve approximately 263,000 connections in the states of California, New Hampshire, Missouri, Kansas, Oklahoma and Arkansas.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 335,000 connections located in the states of Georgia, Illinois, Iowa, Massachusetts, New Hampshire and Missouri.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 182,000 connections located in the states of Arkansas, Arizona, California, Illinois, Missouri, Montana, and Texas.

2017 First Quarter Usage Results

Electric Distribution Systems

	Three Months Ended March 31	
	2017	2016
Average Active Electric Connections For The Period		
Residential	223,400	80,300
Commercial and industrial	39,000	12,400
Total Average Active Electric Connections For The Period	262,400	92,700
Customer Usage (GW-hrs)		
Residential	643.3	165.8
Commercial and industrial	818.5	219.5
Total Customer Usage (GW-hrs)	1,461.8	385.3

For the three months ended March 31, 2017 the electric distribution systems' usage totaled 1,461.8 GW-hrs as compared to 385.3 GW-hrs for the same period in 2016, an increase of 1,076.5 GW-hrs or 279.4%. The addition of Empire accounted for 1,071.8 GW-hrs of the increase. The CalPeco Electric System and Granite State Electric System usage totaled 390.0 GW-hrs, an increase of 4.7 GW-hrs or 1.2%.

Natural Gas Distribution Systems

Three Months Ended
March 31

2017 2016

Average Active Natural Gas Connections For The Period

Residential	291,200	252,400
Commercial and industrial	32,200	27,100

Total Average Active Natural Gas Connections For The Period	323,400	279,500
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Customer Usage (MMBTU)

Residential	8,445,000	7,870,000
Commercial and industrial	4,842,000	4,837,000

Total Customer Usage (MMBTU)	13,287,000	12,707,000
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For the three months ended March 31, 2017, usage at the natural gas distribution systems totaled 13,287,000 MMBTU as compared to 12,707,000 MMBTU during the same period in 2016, an increase of 580,000 MMBTU, or 4.6%. The addition of Empire accounted for 1,390,000 MMBTU of the increase. Excluding the addition of Empire, usage totaled 11,897,000 MMBTU, a decrease of 810,000 MMBTU, or 6.4%. The decrease was primarily due to lower demand and heating degree days in the Midstates and Peach State Gas Systems during the three months ended March 31, 2017 as compared to the same period in the prior year.

Water and Wastewater Distribution Systems

Three Months Ended
March 31

2017 2016

Average Active Connections For The Period

Wastewater connections	40,800	40,200
Water distribution connections	134,800	131,300

Total Average Active Connections For The Period	175,600	171,500
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Gallons Provided

Wastewater treated (millions of gallons)	589	598
Water sold (millions of gallons)	3,370	3,066

Total Gallons Provided	3,959	3,664
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During the three months ended March 31, 2017, the water and wastewater distribution systems provided approximately 3,370 million gallons of water to its customers and treated approximately 589 million gallons of wastewater as compared to 3,066 million gallons of water provided and 598 million gallons of wastewater treated during the same period in 2016. The increase in the gallons of water provided to customers can be primarily attributed to increased water usage at the Park Water systems in California.

2017 First Quarter Operating Results

	Three Months Ended March 31			
	2017 U.S. \$ (millions)	2016 U.S. \$ (millions)	2017 Can \$ (millions)	2016 Can \$ (millions)
Revenue				
Utility electricity sales and distribution	\$ 181.5	\$ 46.1	\$ 240.1	\$ 63.4
Less: cost of sales – electricity	(54.6)	(28.4)	(72.3)	(39.2)
Net Utility Sales - electricity	126.9	17.7	167.8	24.2
Utility natural gas sales and distribution	136.9	109.5	181.2	151.4
Less: cost of sales – natural gas	(61.6)	(46.7)	(81.4)	(64.7)
Net Utility Sales - natural gas	75.3	62.8	99.8	86.7
Utility water distribution & wastewater treatment sales and distribution	32.4	30.0	42.9	41.1
Less: cost of sales – water	(2.0)	(2.0)	(2.7)	(2.8)
Net Utility Sales - water distribution & wastewater treatment	30.4	28.0	40.2	38.3
Gas transportation	10.9	9.0	14.5	12.4
Other revenue	1.9	0.8	2.6	1.1
Net Utility Sales	245.4	118.3	324.9	162.7
Operating expenses	(98.0)	(50.0)	(129.7)	(68.8)
Other income	1.0	1.0	1.3	1.2
HLBV	\$ 1.6	\$ —	\$ 2.1	\$ —
Divisional Operating Profit¹	\$ 150.0	\$ 69.3	\$ 198.6	\$ 95.1

¹ Certain prior year items have been reclassified to conform with current year presentation.

For the three months ended March 31, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. \$150.0 million as compared to U.S. \$69.3 million for the comparable period in the prior year. Measured in Canadian dollars, the group's operating profit was \$198.6 million as compared to \$95.1 million during the same period in 2016, which represents an increase of \$103.5 million or 109%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in \$ millions)		Three Months Ended March 31
Prior Period Operating Profit	\$	95.1
Existing Facilities		
Electricity: Increase is primarily due to lower operating costs at the CalPeco and Granite State Electric systems.		1.7
Gas: Increase is primarily due to higher demand and colder weather conditions at the EnergyNorth Gas System. Usage at the Midstates and Georgia Gas Systems were lower as compared to the prior year, however, operating profit was consistent due decoupling measures implemented at these utilities.		3.7
Water: Increase is primarily due to increased usage at the Park Water System.		0.5
Other		0.1
		6.0
New Facilities		
Electricity: Acquisition of Empire on January 1, 2017. In the first quarter Empire's electric operations experienced lower than normal heating degree days which resulted in a negative operating profit variance of U.S. \$11.7 million.		81.3
Gas: Acquisition of Empire on January 1, 2017. In the first quarter Empire's gas operations experienced lower than normal heating degree days which resulted in a negative operating profit variance of U.S. \$2.7 million		5.1
Water: Acquisition of Empire on January 1, 2017.		0.2
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		2.7
		89.3
Rate Cases		
Electricity: Implementation of new rates at the CalPeco Electric System due to the general rate case and inclusion of the Luning Solar Facility in rate base, as well as interim rates at the Granite State Electric System.		5.1
Gas: Implementation of new rates at the Peach State, Missouri, Iowa and New England Gas systems.		6.2
Water: Implementation of new rates at the Rio Rico and Bella Vista water systems.		0.5
		11.8
Foreign Exchange		(3.6)
Current Period Divisional Operating Profit	\$	198.6

Regulatory Proceedings

The following table summarizes the major regulatory proceedings currently underway within the Liberty Utilities Group:

Utility	State	Regulatory Proceeding Type	Rate Request U.S. \$ (millions)	Current Status
Completed Rate Cases				
Granite State Electric System	New Hampshire	General Rate Case	\$7.7	Final Order issued in April 2017 approving a U.S. \$6.2 million rate increase effective May 1, 2017, and two additional annual increases of U.S. \$0.2 million to U.S.\$0.3 million effective May 1, 2018 and May 1, 2019.
New England Gas	Massachusetts	Gas System Enhancement Plan (GSEP)	\$3.8	Final Order issued in April 2017 approving a U.S. \$2.9 million rate increase effective May 1, 2017.
Iowa Gas System	Iowa	General Rate Case	\$1.1	Final Order issued in April 2017 approving a U.S. \$1.0 million rate increase effective either June or July 2017.
Peach State Gas System	Georgia	Gas Rate Adjustment Mechanism	\$0.7	Final Order issued in February 2017 approving a U.S. \$0.7 million rate increase effective February 1, 2017.
Entrada Del Oro	Arizona	General Rate Case	\$0.3	Final Order issued in March 2017 approving a U.S. \$0.2 million rate increase effective April 1, 2017.
Pending Rate Cases				
EnergyNorth Gas System	New Hampshire	General Rate Case	\$19.9	On April 27, 2017, filed an application seeking an increase of U.S. \$13.8 million, plus a step increase of U.S. \$6.1 million to be implemented in June 2018. Temporary rates of U.S. \$7.8 million were requested to be effective as of July 1, 2017.
Litchfield Park Water & Sewer	Arizona	General Rate Case	\$5.1	On February 28, 2017, filed a water/sewer rate application (test year December 31, 2016) seeking an increase of U.S. \$5.1 million in rates. New rates are expected to be effective Q1 2018.
CalPeco Electric	California	Turquoise Solar Project	\$3.5	On December 14, 2016, filed an application seeking approval to include the 10 MWac Turquoise Solar Project into rate base as of January 1, 2018 through Post Test-Year Adjustment Mechanism ("PTAM") scheduled to be filed October 2017.
Illinois Gas System	Illinois	General Rate Case	\$3.0	Final hearing concluded in March 2017 approving a U.S. \$2.2 million rate increase for rates effective July 1 2017. Order is expected to be issued in June 2017.
Oklahoma Electricity System	Oklahoma	General Rate Case	\$3.0	On December 21, 2016, filed an application seeking incremental revenues of U.S. \$3.8 million (revised to U.S. \$3.0 million). Approvals expected by July 2017, with rates effective August 2017. Interim rates may be implemented in July 2017.
Woodmark/Tall Timbers Water & Wastewater Systems	Texas	General Rate Case	\$2.0	On September 6, 2016, filed an application seeking a U.S. \$2.0 million revenue increase. A final decision is expected in Q4 2017.
Kansas Asbury Environmental and Riverton Cost Recovery ("AERR") Rider	Kansas	Rate Rider Recovery	\$1.9	On January 6, 2017, filed an applications in Kansas for the Asbury Environmental and Riverton Cost Recovery ("AERR") Rider seeking an incremental revenue increase of U.S. \$1.9 million. The revised rider rates are expected to be implemented by no later than September 2017.
New England Gas	Massachusetts	Decoupling Filing	\$0.2	On February 1, 2017, filed a revenue decoupling filing with the Massachusetts Department of Public Utilities ("MDPU") seeking a recovery for reconciliation of 2016 off-peak period (May – October) which would allow for U.S. \$0.2 million incremental revenue increase. New rates are expected to take effect May 1, 2017.

Completed Rate Cases

On April 29, 2016, the Granite State Electric System filed a rate application. The application sought a U.S. \$5.3 million annual revenue increase proposed for effect July 1, 2016, plus an additional U.S. \$2.4 million annual increase (step increase) to recover the revenue requirement associated with capital additions made in 2016. The total permanent and step increase being proposed is U.S. \$7.7 million annually, or a 21.8% increase to distribution revenue. In June 2016, approval of a temporary rate increase of U.S. \$2.4 million was issued, effective July 1, 2016. The final permanent revenue increase will be retroactive to the temporary rate effective date. In April 2017 an Order was issued by the New Hampshire Public Utilities Commission approving a U.S. \$3.8 million increase to annual distribution revenues along with an annual increase of U.S. \$2.5 million for the revenue requirement associated with 2016 capital investment, both effective May 1, 2017 (achieving 82% of the requested increase). The difference between the U.S. \$3.8 million permanent increase and the U.S. \$2.4 million temporary rate level that was in effect since July 1, 2016 will be collected beginning May 1, 2017. The settlement also provides for two additional annual increases of approximately U.S. \$0.3 million effective May 1, 2018 and May 1, 2019 to recover the revenue requirement associated with certain significant capital investments made during the prior calendar year. The rates are based on a return on equity ("ROE") of 9.4% and 50.0% equity.

In October 2016, the New England Natural Gas System filed its Gas System Enhancement Plan (GSEP) application seeking incremental revenue requirement of U.S. \$3.8 million for an effective date of May 1, 2017. The Order was issued in April 2017 approving a revenue requirement of U.S. \$2.9 million, effective May 1, 2017, to recover costs over the period of May 1, 2017 to April 30, 2018. The Company's GSEP filing outlined a 4-year replacement plan, in which the Company anticipates replacing 14 miles of aging infrastructure along with the replacement and/or transfer of 983 gas services.

APUC: CORPORATE AND OTHER EXPENSES

(all dollar amounts in \$ millions)	Three Months Ended March 31	
	2017	2016
Corporate and other expenses:		
Administrative expenses	\$ 14.6	\$ 11.4
Loss (gain) on foreign exchange	0.1	(0.3)
Interest expense on convertible debentures and acquisition facility due to the acquisition of Empire	17.6	5.9
Interest expense	46.9	19.2
Interest, dividend, equity, and other income ¹	(0.7)	(0.9)
Other losses ²	—	5.0
Acquisition-related costs	60.4	6.3
Loss on derivative financial instruments	1.4	0.9
Income tax expense	19.4	18.5

¹ Excludes income directly pertaining to the Liberty Power and Liberty Utilities Groups (disclosed in the relevant sections).

² Includes Other Gains and Loss on long-lived assets, net per the Statement of Operations.

2017 First Quarter Corporate and Other Expenses

During the three months ended March 31, 2017, administrative expenses totaled \$14.6 million as compared to \$11.4 million in the same period in 2016. The \$3.2 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth.

For the three months ended March 31, 2017, interest expense on convertible debentures and acquisition financing totaled \$17.6 million. (See *Convertible Unsecured Subordinated Debentures and note 10 in the Unaudited Interim Consolidated Financial Statements*.)

For the three months ended March 31, 2017, interest expense totaled \$46.9 million as compared to \$19.2 million in the same period in 2016. The increase is primarily attributable to assumed and incremental Empire Acquisition debt, and new debt raised at Liberty Power. (See *Credit Facilities & Debt and note 7 in the Unaudited Interim Consolidated Financial Statements*.)

For the three months ended March 31, 2017 other losses were \$nil as compared to a loss of \$5.0 million in the same period in 2016. The prior period loss is primarily due to the write off of the Company's equity interest in transmission development projects.

For the three months ended March 31, 2017, acquisition-related costs totaled \$60.4 million as compared to \$6.3 million in the same period in 2016. The increase is primarily attributable to the Empire Acquisition.

For the three months ended March 31, 2017, loss on derivative financial instruments totaled \$1.4 million as compared to \$0.9 million in the same period in 2016.

For the three months ended March 31, 2017, income tax expense of \$19.4 million was recorded as compared to income tax expense of \$18.5 million during the same period in 2016. The increase in income tax expense is primarily due to the impact of the acquisition of Empire and increased HLBV earnings offset by the impact of additional interest expense.

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to Net Earnings

The following table is derived from and should be read in conjunction with the unaudited interim consolidated statements of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

(all dollar amounts in \$ millions)	Three Months Ended March 31	
	2017	2016
Net earnings attributable to shareholders	\$ 26.0	\$ 42.0
Add (deduct):		
Net earnings attributable to the non-controlling interest, exclusive of HLBV	1.0	1.7
Income tax expense	19.4	18.5
Interest expense on convertible debentures and acquisition financing	17.6	5.9
Interest expense on long-term debt and others	46.9	19.2
Other gains	—	(1.2)
Loss on long-lived assets, net	—	6.2
Acquisition-related costs	60.4	6.3
Loss on derivative financial instruments	1.4	0.9
Realized gain on energy derivative contracts	(0.7)	(1.0)
Loss (gain) on foreign exchange	0.1	(0.3)
Depreciation and amortization	82.7	49.7
Adjusted EBITDA	\$ 254.8	\$ 147.9

HLBV represents the value of net tax attributes earned during the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. HLBV earned in the three months ended March 31, 2017 amounted to \$21.5 million.

Reconciliation of Adjusted Net Earnings to Net Earnings

The following table is derived from and should be read in conjunction with the unaudited interim consolidated statements of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Net Earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with GAAP.

The following table shows the reconciliation of net earnings to Adjusted Net Earnings exclusive of these items:

(all dollar amounts in \$ millions)	Three Months Ended March 31	
	2017	2016
Net earnings attributable to shareholders	\$ 26.0	\$ 42.0
Add (deduct):		
Loss on derivative financial instruments	1.4	0.9
Realized gain on derivative financial instruments	(0.7)	(1.0)
Loss on long-lived assets, net	—	6.2
Loss (gain) on foreign exchange	0.1	(0.3)
Interest expense on convertible debentures and acquisition financing	17.6	5.9
Acquisition-related costs	60.4	6.3
Adjustment for taxes	(16.7)	(3.9)
Adjusted Net Earnings	\$ 88.1	\$ 56.1
Adjusted Net Earnings per share¹	\$ 0.25	\$ 0.21

¹ Per share amount calculated after preferred share dividends and excluding subscription receipts issued for projects or acquisitions not reflected in earnings.

For the three months ended March 31, 2017, Adjusted Net Earnings totaled \$88.1 million as compared to Adjusted Net Earnings of \$56.1 million, an increase of \$32.0 million as compared to the same period in 2016. The increase in Adjusted Net Earnings for the three months ended March 31, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2016.

Reconciliation of Adjusted Funds from Operations to Cash Flows from Operating Activities

The following table is derived from and should be read in conjunction with the unaudited interim consolidated statements of operations and unaudited interim consolidated statement of cash flows. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Funds from Operations and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to funds from operations in accordance with GAAP.

The following table shows the reconciliation of funds from operations to Adjusted Funds from Operations exclusive of these items:

(all dollar amounts in \$ millions)	Three Months Ended March 31	
	2017	2016
Cash flows from operating activities	\$ 83.8	\$ 53.4
Add (deduct):		
Changes in non-cash operating items	46.3	46.7
Production based cash contributions from non-controlling interests	9.1	9.5
Interest expense on convertible debentures and acquisition financing fees ¹	9.3	5.9
Acquisition-related costs	60.4	6.3
Adjusted Funds from Operations	\$ 208.9	\$ 121.8

¹ Exclusive of deferred financing fees of \$8.3 million.

For the three months ended March 31, 2017, Adjusted Funds from Operations totaled \$208.9 million as compared to Adjusted Funds from Operations of \$121.8 million, an increase of \$87.1 million as compared to the same period in 2016.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES¹

(all dollar amounts in \$ millions)	Three Months Ended March 31	
	2017	2016
Liberty Power Group:		
Maintenance	\$ 7.8	\$ 11.4
Investment in Growth Capital Projects ¹	440.3	16.8
	\$ 448.1	\$ 28.2
Liberty Utilities Group:		
Rate Base Maintenance	\$ 56.5	\$ 28.3
Rate Base Acquisition	2,739.5	345.3
Rate Base Growth	132.7	4.0
	\$ 2,928.7	\$ 377.6
Corporate	—	—
Total Capital Expenditures	\$ 3,376.8	\$ 405.8

¹ Includes expenditures on Property Plant & Equipment, equity-method investees, and acquisitions of operating entities that were jointly developed by the company.

2017 First Quarter Property Plant and Equipment Expenditures

During the three months ended March 31, 2017, the Liberty Power Group incurred capital expenditures of \$448.1 million as compared to \$28.2 million during the same period in 2016. The increase in capital expenditures are primarily due to the acquisition of the remaining outstanding interest in the Deerfield Wind Facility. The balance of capital expenditures were for the construction of the Great Bay Solar project and ongoing maintenance at operating sites.

During the three months ended March 31, 2017, the Liberty Utilities Group incurred capital expenditures of \$2,928.7 million as compared to \$377.6 million during the same period in 2016. The increase in capital expenditures are primarily due to the acquisition of Empire in January 2017 (U.S. \$2,058.2 million), and completion of the Luning Solar Facility located in Mineral County, Nevada, in February 2017 (U.S. \$84.9 million). In the prior year, the Liberty Utilities Group completed the acquisition of the Park Water System in January 2016. Other capital expenditures related to reliability enhancements, improvements and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection initiatives relating to safety and reliability at the electric and gas systems.

2017 Capital Investments

In 2017, the company plans to spend between \$1.1 billion and \$1.3 billion on capital investment opportunities. Actual expenditures during the course of 2017 may vary due to timing of various project investments and the realized U.S. dollar exchange rate.

Expected 2017 capital investment ranges are as follows:

(all dollar amounts in \$ millions)	
Liberty Power Group:	
Maintenance	\$ 40.0 - \$ 50.0
Investment in Growth Capital Projects	500.0 - 580.0
Total Liberty Power Group:	\$ 540.0 - \$ 630.0
Liberty Utilities Group:	
Rate Base Maintenance	\$ 160.0 - \$ 170.0
Rate Base Growth	400.0 - 500.0
Total Liberty Utilities Group:	\$ 560.0 - \$ 670.0
Total 2017 Capital Investments	\$ 1,100.0 - \$ 1,300.0

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, funds committed by tax equity investors, revolving credit facilities, as well as the debt and equity capital markets to finance its 2017 capital investments.

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving credit and letter of credit facilities available for Corporate, the Liberty Power Group, and the Liberty Utilities Group to manage the liquidity and working capital requirements of each division (collectively the "Bank Credit Facilities").

Bank Credit Facilities

The following table sets out the Bank Credit Facilities available to APUC and its operating groups as at March 31, 2017:

(all dollar amounts in \$ millions)	As at March 31, 2017				As at Dec 31, 2016
	Corporate	Liberty Power	Liberty Utilities	Total	Total
Committed facilities	\$ 65.0	\$ 439.9	\$ 532.4	\$ 1,037.3	\$ 773.8
Funds drawn on facilities	—	(223.1)	—	(223.1)	(242.9)
Letters of credit issued	(12.0)	(135.6)	(43.5)	(191.1)	(234.9)
Liquidity available under the facilities	53.0	81.2	488.9	623.1	296.0
Cash on hand				77.7	110.4
Total Liquidity and Capital Reserves	\$ 53.0	\$ 81.2	\$ 488.9	\$ 700.8	\$ 406.4

As at March 31, 2017, the Company's \$65.0 million senior unsecured bilateral revolving credit facility (the "Corporate Credit Facility") was undrawn and had \$12.0 million of outstanding letters of credit. The facility matures on November 19, 2017 and is subject to customary covenants.

As at March 31, 2017, the Liberty Power Group's committed bank lines consisted of a \$350.0 million senior unsecured syndicated revolving credit facility and \$89.9 million letter of credit facility (Cdn \$50.0 million and U.S. \$30.0 million). Subsequent to quarter end, Liberty Power entered into a \$150.0 million senior unsecured bilateral revolving credit facility with a Canadian Chartered Bank. The new facility matures on May 19, 2018.

As at March 31, 2017, the Liberty Utilities Group's committed bank lines consisted of a U.S. \$200.0 million senior unsecured syndicated revolving credit facility at the holding company and a U.S. \$200.0 million revolving credit facility at Empire ("Empire Facility"). The facilities mature on September 30, 2018 and October 20, 2019 respectively. The Empire Facility is used primarily as a backstop to commercial paper issued by Empire (rated P2 Moody's / A2 S&P).

On February 9, 2016, in connection with the acquisition of Empire, the Company obtained U.S. \$1.6 billion in acquisition financing commitments ("Acquisition Facility") from a syndicate of banks. On December 30, 2016 the Company drew U.S. \$1,336.4 million on the Acquisition Facility in connection with the closing of the Empire Acquisition. The Acquisition Facility was fully repaid in the first quarter from proceeds received from the Final Installment payment and the Liberty Private Placement.

Long Term Debt

On January 17, 2017 the Liberty Power Group issued \$300.0 million of senior unsecured debentures bearing interest at 4.09% with a maturity date of February 17, 2027. The debentures were sold at a price of \$99.929 per \$100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars for an effective yield of 4.86%.

On March 1, 2017, the Liberty Utilities Group entered into a Note Purchase Agreement for the issuance of U.S. \$750.0 million of senior unsecured notes ("Liberty Private Placement") with 29 institutional investors in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%. In anticipation of the financing, Liberty Utilities had entered into forward contracts to lock in the underlying U.S. Treasury interest rates (see "Interest Rate Risk section"). Considering the effect of the hedges, the effective weighted average rate paid by The Liberty Utilities Group is 3.6%. The offering closed on March 24, 2017, the proceeds of which were applied to repay the balance of the Acquisition Facility and other existing indebtedness.

As at March 31, 2017, the weighted average tenure of APUC's total long term debt is approximately 11 years with an average interest rate of approximately 4.5%.

Convertible Unsecured Subordinated Debentures

In first quarter of 2016, in connection with the acquisition of Empire, the Company completed the sale of \$1.15 billion aggregate principal amount of 5.0% convertible debentures ("Debentures"). The convertible debentures were sold on an instalment basis at a price of \$1,000 principal amount debenture, of which \$333 was received on closing of the debenture offering and the remaining \$667 (the "Final Installment") received on February 2, 2017 which was a date set by the Company following the satisfaction of conditions precedent to the closing of the Empire Acquisition. The proceeds received from the First and Final Installment were \$383.0 million and \$767.1 million, respectively. As the Final Installment date occurred prior to the first anniversary of the closing of the debenture offering, holders of the convertible debentures who paid the final instalment by February 2, 2017 received, in addition to the payment of accrued and unpaid interest, a make-whole payment representing the interest that would have accrued from the day following the Final Installment date up to and including March 1, 2017.

As at May 10, 2017, a total of 108,075,037 common shares of the company were issued, representing conversion into common shares of 99.6% of the convertible debentures. Any debentures not converted may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest. The convertible debentures mature on March 31, 2026 and currently bear interest at an annual rate of 0%. At maturity, the Company will have the right to pay the principal amount due in cash or in common shares. In the case of common shares, such shares will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

Credit Ratings

APUC has a long term consolidated corporate credit rating of BBB (flat) from Standard & Poor's ("S&P") and a BBB (low) rating from DBRS Limited ("DBRS"). Algonquin Power Co ("APCo"), the parent company for the Liberty Power Group, has a BBB (flat) issuer rating from S&P and BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1 ("Liberty Finance"), a special purpose financing entity of Liberty Utilities Co., the parent company for the Liberty Utilities Group, has a BBB (high) issuer rating from DBRS.

On February 6, 2017, following the announcement that APUC had received the Final Instalment proceeds from the Debentures, S&P revised the outlook on APUC's consolidated corporate credit rating from negative to stable. S&P had placed APUC's consolidated credit rating on negative watch on February 9, 2016, pending the completion of the Empire acquisition and the execution on the financing plan, including the receipt of the Final Instalment and conversion of the Debentures to common shares of the Company. S&P's reiteration of the outlook reflects their assessment of APUC's stable cash flows from its regulated utilities and contracted unregulated power business, along with its commitment to a balance between debt and equity to fund its acquisition and development activities such that its funds from operations-to-debt ratio remains in the 14%-15% range.

On February 13, 2017, following the announcement that APUC had received the Final Instalment proceeds from the Debentures, DBRS removed the "Under Review with Developing Implications" status from the ratings of APUC and its subsidiaries. DBRS had placed APUC's ratings as "Under Review with Developing Implications" on February 10, 2016 pending completion of the acquisition and execution of the financing plan, including the receipt of the Final Instalment proceeds. DBRS reiterated their view that the acquisition of Empire will have a positive impact on APUC's and Liberty Finance's business risk assessment. The impact on their financial risk assessment was cited as modestly negative, with the overall impact on the ratings as neutral. DBRS also reiterated that the rating actions for APCo reflect their view that the acquisition of Empire has no impact on the business or financial risk assessments of APCo.

Contractual Obligations

Information concerning contractual obligations as of March 31, 2017 is shown below:

(all dollar amounts in \$ millions)	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Principal repayments on debt obligations ¹	\$ 4,704.4	\$ 435.6	\$ 717.4	\$ 755.8	\$ 2,795.6
Convertible debentures	5.2	—	—	—	5.2
Advances in aid of construction	109.2	3.1	—	—	106.1
Interest on long-term debt obligations	2,067.1	188.7	320.1	264.5	1,293.8
Purchase obligations	477.4	477.4	—	—	—
Environmental obligations	95.8	8.0	19.7	7.6	60.5
Derivative financial instruments:					
Cross currency swap	102.2	6.3	11.4	81.9	2.6
Interest rate swap	14.5	—	14.5	—	—
Commodity contracts	4.2	2.1	2.1	—	—
Purchased power	541.6	64.4	102.4	93.6	281.2
Gas delivery, service and supply agreements	438.9	105.3	149.1	74.8	109.7
Service agreements	736.8	46.2	95.2	101.9	493.5
Capital projects	88.2	68.7	19.4	0.1	—
Operating leases	295.0	10.5	19.6	17.9	247.0
Other obligations	184.5	52.9	—	—	131.6
Total Obligations	\$ 9,865.0	\$ 1,469.2	\$ 1,470.9	\$ 1,398.1	\$ 5,526.8

¹ Exclusive of deferred financing costs, bond premium/discount and fair value adjustments at the time of issuance or acquisition.

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the trading symbol "AQN". As at March 31, 2017, APUC had 384,672,285 issued and outstanding common shares.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

In the first quarter of 2016, in connection with the acquisition of Empire, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, \$1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures of APUC.

All Debentures were sold on an instalment basis at a price of \$1,000 dollars per Debenture, of which \$333 dollars was paid on the closing of the Offering and the remaining \$667 dollars was payable on a date set by APUC upon satisfaction of all conditions precedent to the closing of APUC's acquisition of Empire ("The Final Instalment Date"), at which time each debenture was convertible to 94.3396 common shares of APUC and bears an interest rate of 0% thereafter.

The Final Instalment Date was established as February 2, 2017, at which time APUC received the Final Instalment payment and concurrently issued 98,022,082 of its common shares as a result of the conversion of \$1,039.0 million of debentures to equity. As of May 10, 2017, \$4.4 million of convertible debentures remain outstanding.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at March 31, 2017, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon Wind Energy LP; and

- 4,000,000 cumulative rate reset Series D preferred shares, yielding 5.0% annually for the initial five year period ending on March 31, 2019.

APUC has a shareholder dividend reinvestment plan (the “Reinvestment Plan”) for registered holders of common shares of APUC. As at March 31, 2017, 61,419,484 common shares representing approximately 16% of total common shares outstanding had been registered with the Reinvestment Plan. During the quarter ended March 31, 2017, 823,738 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on April 14, 2017, an additional 821,936 common shares were issued under the Reinvestment Plan.

Base Shelf Prospectus

On March 17, 2017 APUC filed a base shelf prospectus allowing for the issuance of up to \$2 billion of specified securities in both Canada and the US.

SHARE BASED COMPENSATION PLANS

For the three months ended March 31, 2017, APUC recorded \$2.3 million in total share-based compensation expense as compared to \$1.0 million for the same period in 2016. There is no significant tax benefit associated with the share-based compensation expense. The compensation expense is recorded as part of administrative expenses in the unaudited interim consolidated statement of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at March 31, 2017, total unrecognized compensation costs related to non-vested options and share unit awards were \$6.1 million and \$5.1 million, respectively, and are expected to be recognized over a period of 2.03 and 2.29 years, respectively.

Stock Option Plan

APUC has a stock option plan that permits the grant of share options to key officers, directors, employees and selected service providers. Except in certain circumstances, the term of an option shall not exceed ten (10) years from the date of the grant of the option.

APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. During the three months ended March 31, 2017, the Company granted 2,328,343 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of \$12.82, the market price of the underlying common share at the date of grant. In March 2017, executives of the Company exercised 1,469,362 stock options at a weighted average exercise price of \$7.81 in exchange for common shares issued from treasury and 165,139 options were settled at their cash value as payment for tax withholdings related to the exercise of the options.

As at March 31, 2017, a total of 6,738,856 options are issued and outstanding under the plan.

Performance Share Units

APUC issues performance share units (“PSUs”) to certain members of management as part of APUC's long-term incentive program. During the three months ended March 31, 2017, the Company granted (including dividends and performance adjustments) 398,361 PSUs to executives and employees of the Company. During the year the Company settled 365,437 PSUs, of which 173,499 PSUs were exchanged for common shares issued from treasury and 182,463 PSUs were settled at their cash value as payment for tax withholdings related to the settlement of the PSUs. Additionally, during the quarter a total of 967 PSUs were forfeited.

As at March 31, 2017, a total of 610,945 PSUs are granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Directors' Deferred Share Unit Plan. Under the plan, non-employee directors of APUC receive 50% of their annual compensation in deferred share units (“DSUs”) and may elect to receive any portion of their remaining compensation in DSUs. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSUs in cash, these DSUs are accounted for as equity awards. During the three months ended March 31, 2017, the Company issued 17,510 DSUs (including DSUs in lieu of dividends) to the directors of the Company.

As at March 31, 2017, a total of 242,173 DSUs had been granted under the DSU plan.

Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the “ESPP”) which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the three months ended March 31, 2017, the Company issued 137,612 common shares to employees under the ESPP.

As at March 31, 2017, a total of 633,642 shares had been issued under the ESPP.

RELATED PARTY TRANSACTIONS

Emera Inc.

A member of the Board of APUC is an executive at Emera. During the three months ended March 31, 2017, the Energy Services Business sold electricity to Maine Public Service Company and Bangor Hydro, both of which are subsidiaries of Emera, amounting to U.S. \$3.0 million as compared to U.S. \$2.6 million during the same period in 2016. During the three months ended March 31, 2017, the Liberty Utilities Group purchased natural gas amounting to U.S. \$0.9 million as compared to U.S. \$1.9 million during the same period in 2016 from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction. In 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply, and construction agreement for the Tinker transmission upgrade project. The transmission upgrade was placed in service in April 2017 with final completion of the contract work expected in June 2017. The total cost of the contract is estimated at \$8.8 million. The contract followed a market-based request for proposal process.

There was U.S. \$2.6 million included in accruals for the three months ended March 31, 2017, as compared to U.S. \$0.3 million during the same period in 2016, related to these transactions.

Equity-method investments

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, for the three months ended March 31, 2017, the Company charged its equity-method investees \$0.4 million as compared to \$0.7 million during the same period in 2016.

Trafalgar

In 2016, the Company received U.S. \$10.1 million in proceeds from the settlement of the Trafalgar matter, and paid U.S. \$2.9 million to an entity partially and indirectly owned by Senior Executives as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. \$6.6 million was recorded in 2016.

Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. (“APC”) which was partially owned by Senior Executives. APC owns the partnership interest in the 18 MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction is expected to be settled in 2017.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

ENTERPRISE RISK MANAGEMENT

An enterprise risk management (“ERM”) framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of our objectives. The risks discussed below are not intended as a complete list of all exposures that APUC is encountering or may encounter. A further assessment of APUC and its subsidiaries’ business risks is also set out in the most recent AIF and the annual MD&A.

Interest Rate Risk

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to interest rate risk. Borrowings subject to variable interest rates are as follows:

- The Corporate revolving credit facility is subject to a variable interest rate and had no amounts outstanding as at March 31, 2017. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Liberty Power Group revolving credit facility is subject to a variable interest rate and had \$223.1 million outstanding as at March 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by \$2.2 million annually;

- The Liberty Utilities Group revolving credit facility is subject to a variable interest rate and had no amounts outstanding as at March 31, 2017. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Liberty Utilities Group commercial paper program is subject to a variable interest rate and had \$10.0 million (U.S. \$7.5 million) outstanding as at March 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by \$0.1 million annually;
- The Corporate term credit facility is subject to a variable interest rate and had \$179.7 million (U.S. \$135.0 million) outstanding as at March 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by \$1.8 million annually; and
- The Park Water System term credit facility is subject to a variable interest rate and had \$29.9 million (U.S. \$22.5 million) outstanding as at March 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by \$0.3 million annually.

APUC does not actively manage interest rate risk on its variable interest rate borrowings due to the primarily short term and revolving nature of the amounts drawn.

Litigation Risks and Other Contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

Long Sault Global Adjustment Claim

In December 2012, N-R Power and Energy Corp., Algonquin Power (Long Sault) Partnership and N-R Power Partnership (“Long Sault”) commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC’s interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global adjustment as a price escalator. On October 21, 2016, following numerous unsuccessful court proceedings, the OEFC made retroactive payments of \$5.1 million and \$0.3 million of interest to Long Sault. OEFC also sought leave to appeal to the Supreme Court of Canada (the “SCC”). On January 19, 2017, the SCC denied OEFC’s application for leave to appeal.

Market Price Risk

The Liberty Power Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the Liberty Power Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Company is not able to generate the specified amount of power at the specified time resulting in production shortfalls under the hedge that then requires the Company to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Liberty Power Group generally seeks to structure hedges to cover less than 100% of the anticipated production, thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to grid curtailments or mechanical failures, production shortfalls may be such that the Liberty Power Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

Hedges currently put in place by the Liberty Power Group along with residual exposures to the market are detailed below:

The July 1, 2012 acquisition of the Sandy Ridge Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility’s expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 44,000 MW-hrs. Therefore, each U.S. \$10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. \$0.4 million for the year.

The December 10, 2012 acquisition of the Senate Wind Facility included a physical hedge, which commenced on January 1, 2013, for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility’s expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs. Therefore, each U.S. \$10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. \$2.0 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility’s expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs. Therefore, each U.S. \$10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. \$2.0 million for the year.

Under each of the above noted hedges, if production is not sufficient to meet the unit quantities under the hedge, the shortfall must be purchased in the open market at market rates. The effect of this risk exposure could be material but cannot be quantified as it is dependent on both the amount of shortfall and the market price of electricity at the time of the shortfall.

In addition to the above noted hedges, from time to time the Liberty Power Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at March 31, 2017, the Liberty Power Group had not entered into any such short-term derivative contracts.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on June 1, 2012, for a 20 year period. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production based on expected long term average production, each U.S. \$10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. \$0.5 million for the year.

Regulatory Risk

Profitability of APUC businesses is, in part, dependent on regulatory climates in the jurisdictions in which those businesses operate. In the case of some Liberty Power Group hydroelectric facilities, water rights are generally owned by governments that reserve the right to control water levels, which may affect revenue.

Condemnation Expropriation Proceedings

Mountain Water is currently the subject of a condemnation lawsuit filed by the city of Missoula. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision that the city of Missoula can proceed with condemnation of Mountain Water's assets. Upon taking possession of Mountain Water's assets, the compensation to be paid by the city of Missoula for such taking will be the value of the utility (determined by the valuation commissioners on November 17, 2015 to be U.S. \$88.6 million as of May 6, 2014). Mountain Water is expected to receive certain additional amounts that may include legal fees, interest, post-valuation capital expenditures and property tax reimbursement.

On December 22, 2015, various developers filed a lawsuit in Missoula County District Court against Mountain Water and the city of Missoula. The lawsuit pertains to Funded By Other ("FBO") contracts between each developer and Mountain Water. Under these FBO contracts, the developers paid for facilities to provide water service and Mountain Water agreed to refund such amounts over a 40 year period. As of the date of acquisition of Western Water Holdings, the outstanding balance of these advances, on a non-discounted basis, was U.S. \$23.1 million. On February 21, 2017, the court issued an order imposing equitable liens on the Mountain Water assets that are the subject of the FBO contracts, mandating that the liens be satisfied directly from the condemnation award, if and when paid.

On April 27, 2017, Mountain Water agreed in principle to certain terms with the City of Missoula relating to the condemnation of Mountain Water's assets. The city is expected to take possession of Mountain Water's assets in the second quarter or early in the third quarter of 2017.

Subject to final adjustments, APUC expects that the net effect of the foregoing and terms of the original acquisition of Mountain Water will result in Liberty Utilities receiving an amount of approximately U.S. \$103.0 million from the disposition of the utility.

The Town of Apple Valley has initiated a process with the objective to condemn the assets of Liberty Apple Valley. A ballot measure initiated by citizens of Apple Valley and supported by the Company passed during the November 2016 election. This measure requires the Town of Apple Valley to put to a public vote any debt over U.S. \$10.0 million to be issued related to an enterprise fund activity. On March 9, 2017, the Apple Valley Town Council voted to call a special election on June 6, 2017 to approve a ballot measure to authorize the Town to incur U.S. \$150.0 million in bonds for the purpose of funding an attempted taking of the Apple Valley Water System. The entire condemnation process, even if successful, is expected to take several years to resolve.

Cycles and Seasonality

Liberty Power Group

The Liberty Power Group's hydroelectric operations are impacted by seasonal fluctuations and year to year variability of the available hydrology. These assets are primarily "run-of-river" and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Year to year the level of hydrology varies, impacting the amount of power that can be generated in a year.

The Liberty Power Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the spring and fall periods, winds are generally stronger than during the summer periods. The ability of these facilities to generate income may be impacted by naturally occurring changes in wind patterns and wind strength.

The Liberty Power Group's solar generation facilities are impacted by seasonal fluctuations and year to year variability in the solar radiance. For instance, there are more daylight hours in the summer than there are in the winter, resulting in higher

production in the summer months. The ability of these facilities to generate income may be impacted by naturally occurring changes in solar radiance.

The Company attempts to mitigate the above noted natural resource fluctuation risks by acquiring or developing generating stations in different geographic locations.

Liberty Utilities Group

The Liberty Utilities Group's demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease, adversely affecting revenues.

The Liberty Utilities Group's demand for energy from its electric distribution systems is primarily affected by weather conditions and conservation initiatives. The Liberty Utilities Group provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts on revenues.

The Liberty Utilities Group's primary demand for natural gas from its natural gas distribution systems is driven by the seasonal heating requirements of its residential, commercial, and industrial customers. The colder the weather the greater the demand for natural gas to heat homes and businesses. As such, the natural gas distribution systems demand profiles typically peaks in the winter months of January and February and declines in the summer months of July and August. Year to year variability also occurs depending on how cold the weather is in any particular year.

The Company attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, at the Peach State Gas System in Georgia, a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. Not all regulatory jurisdictions in which the Liberty Utilities Group operates have approved mechanisms to mitigate demand fluctuations.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarters ended March 31, 2017:

(all dollar amounts in \$ millions except per share information)	2nd Quarter 2016	3rd Quarter 2016	4th Quarter 2016	1st Quarter 2017
Revenue	\$ 222.8	\$ 221.3	\$ 310.2	\$ 557.9
Net earnings attributable to shareholders from continuing operations	24.8	17.7	46.3	26.0
Net earnings attributable to shareholders	24.8	17.7	46.3	26.0
Net earnings per share from continuing operations	0.08	0.06	0.16	0.07
Net earnings per share	0.08	0.06	0.16	0.07
Adjusted Net Earnings	30.9	26.6	51.4	88.1
Adjusted Net Earnings per share	0.11	0.09	0.18	0.25
Adjusted EBITDA	99.2	91.4	138.3	254.8
Total assets	5,555.0	6,020.8	8,249.5	10,880.7
Long term debt ¹	2,199.9	2,380.8	4,272.0	4,773.6
Dividend declared per common share	\$ 0.14	\$ 0.14	\$ 0.14	\$ 0.15
	2nd Quarter 2015	3rd Quarter 2015	4th Quarter 2015	1st Quarter 2016
Revenue	\$ 196.2	\$ 189.6	\$ 260.3	\$ 341.7
Net earnings attributable to shareholders from continuing operations	20.6	16.7	38.1	42.0
Net earnings attributable to shareholders	19.9	16.5	38.0	42.0
Net earnings per share from continuing operations	0.07	0.06	0.14	0.15
Net earnings per share	0.07	0.05	0.14	0.15
Adjusted Net Earnings	22.2	17.3	39.7	56.1
Adjusted Net Earnings per share	0.08	0.06	0.15	0.21
Adjusted EBITDA	81.1	70.2	109.6	147.9
Total assets	4,396.5	4,759.0	4,991.7	5,615.5
Long term debt ¹	1,440.3	1,613.3	1,486.8	2,214.5
Dividend declared per common share	\$ 0.12	\$ 0.13	\$ 0.13	\$ 0.13

¹ Includes current portion of long-term debt, long-term debt and convertible debentures.

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between \$189.6 million and \$557.9 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between net earnings attributable to shareholders of \$16.5 million and net earnings of \$46.3 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

DISCLOSURE CONTROLS

As of March 31, 2017, APUC carried out an evaluation, under the supervision of and with the participation of APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of March 31, 2017, APUC's disclosure controls and procedures are effective.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management, including the CEO and the CFO, is responsible for establishing and maintaining internal control over financial reporting. Management, as at the end of the period covered by this interim filing, designed internal controls over financial reporting to provide reasonable, but not absolute, assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP. The control framework management used to design the issuer's internal control over financial reporting is that established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

APUC acquired Empire during the three months ended March 31, 2017. The financial information for this acquisition is included in this MD&A and in note 3 to the unaudited interim consolidated financial statements. National Instrument 52-109 and the U.S. Securities and Exchange Commission provide an exemption, whereby companies undergoing acquisitions, can exclude the acquired business in the year of acquisition from the scope of testing and assessment of design and operational effectiveness of controls over financial reporting. Due to the complexity associated with assessing internal controls during integration efforts, the Company plans to utilize the scope exemption as it relates to this acquisition in its management report on internal controls over financial reporting for the year ending December 31, 2017.

For the three months ended March 31, 2017, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. APUC continues to apply its internal control structure over the operations of the acquired business discussed above.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

APUC prepared its unaudited interim consolidated financial statements in accordance with U.S. GAAP. The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of long-lived assets, intangibles, and goodwill, recoverability of deferred tax assets, rate-regulation, unbilled revenue, pension and post-employment benefits, fair value of derivatives and fair value of assets and liabilities acquired in a business combination. Actual results may differ from these estimates.

APUC's significant accounting policies and new accounting standards are discussed in notes 1 and 2 to the unaudited interim consolidated financial statements, respectively.

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	March 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 77,742	\$ 110,417
Accounts receivable, net (note 4)	292,097	189,658
Fuel and natural gas in storage	42,324	21,625
Supplies and consumables inventory	49,056	15,568
Regulatory assets (note 5)	62,674	48,440
Prepaid expenses	41,091	26,562
Derivative instruments (note 21)	17,170	76,631
Other assets	4,084	2,951
	586,238	491,852
Property, plant and equipment, net	8,199,059	4,889,946
Intangible assets, net	63,761	64,989
Goodwill (note 3(a))	1,296,733	306,641
Regulatory assets (note 5)	475,369	243,524
Derivative instruments (note 21)	80,073	74,553
Long-term investments (note 6)	89,458	105,433
Deferred income taxes (note 16)	50,850	30,005
Restricted cash	26,370	2,026,183
Other assets	12,780	16,334
	\$10,880,691	\$ 8,249,460

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	March 31, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	\$ 74,805	\$ 90,592
Accrued liabilities	402,641	308,318
Dividends payable (note 13)	59,648	38,973
Regulatory liabilities (note 5)	51,159	47,769
Long-term debt (note 7)	20,066	10,075
Other long-term liabilities and deferred credits (note 9)	67,411	43,157
Other liabilities	14,207	7,665
	689,937	546,549
Long-term debt (note 7)	4,748,366	3,903,340
Convertible debentures (note 10)	5,196	358,619
Regulatory liabilities (note 5)	217,880	134,965
Deferred income taxes (note 16)	881,037	288,139
Derivative instruments (note 21)	112,431	104,647
Pension and other post-employment benefits obligation (note 8)	268,867	147,845
Other long-term liabilities (note 9)	318,871	232,449
Preferred shares, Series C	17,556	17,552
	6,570,204	5,187,556
Redeemable non-controlling interest	66,757	29,434
Equity:		
Preferred shares	213,805	213,805
Common shares (note 11(a))	3,109,888	1,972,203
Additional paid-in capital	34,638	38,652
Deficit	(594,007)	(556,024)
Accumulated other comprehensive income (note 12)	228,084	254,927
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	2,992,408	1,923,563
Non-controlling interests	561,385	562,358
Total equity	3,553,793	2,485,921
Commitments and contingencies (note 19)		
Subsequent events (notes 5, 6(a), 7, 14, 19(a), 21(b)(iv))		
	\$10,880,691	\$ 8,249,460

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)

	Three Months Ended March 31	
	2017	2016
Revenue		
Regulated electricity distribution	\$ 240,065	\$ 63,396
Regulated gas distribution	196,119	164,279
Regulated water reclamation and distribution	42,930	41,173
Non-regulated energy sales	71,758	65,502
Other revenue	7,045	7,395
	557,917	341,745
Expenses		
Operating expenses	148,877	85,102
Regulated electricity purchased	72,273	39,178
Regulated gas purchased	81,445	64,784
Regulated water purchased	2,659	2,757
Non-regulated energy purchased	7,305	5,615
Administrative expenses	14,648	11,418
Depreciation and amortization	82,705	49,725
Loss (gain) on foreign exchange	80	(302)
	409,992	258,277
Operating income	147,925	83,468
Interest expense on convertible debentures and acquisition financing (notes 7(b) and 10)	17,637	5,863
Interest expense on long-term debt and others	46,925	19,200
Interest, dividend, equity and other income	(3,281)	(2,596)
Other gains	—	(1,216)
Acquisition-related costs (note 3(a))	60,381	6,294
Loss on long-lived assets, net	23	6,185
Loss on derivative financial instruments (note 21(b)(iv))	1,382	942
	123,067	34,672
Earnings	24,858	48,796
Income tax expense (note 16)		
Current	2,584	2,558
Deferred	16,788	15,946
	19,372	18,504
Net earnings	5,486	30,292
Net effect of non-controlling interests (note 15)	(20,473)	(11,744)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	\$ 25,959	\$ 42,036
Series A and D Preferred shares dividend (note 13)	2,600	2,600
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	\$ 23,359	\$ 39,436
Basic net earnings per share (note 17)	\$ 0.07	\$ 0.15
Diluted net earnings per share (note 17)	\$ 0.07	\$ 0.14

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)

Three Months Ended March 31

	2017	2016
Net earnings	\$ 5,486	\$ 30,292
Other comprehensive income:		
Foreign currency translation adjustment, net of tax recovery of \$nil and \$nil, respectively (notes 21(b)(iii) and 21(b)(iv))	(36,781)	(158,547)
Change in fair value of cash flow hedges, net of tax expense of \$3,583 and \$1,486, respectively (note 21(b)(ii))	5,232	21,566
Change in unrealized appreciation in value of available-for-sale investments	2	25
Change in pension and other post-employment benefits, net of tax expense of \$35 and \$92, respectively (note 8)	56	68
Other comprehensive loss, net of tax	(31,491)	(136,888)
Comprehensive loss	(26,005)	(106,596)
Comprehensive loss attributable to the non-controlling interests	(25,121)	(34,017)
Comprehensive loss attributable to shareholders of Algonquin Power & Utilities Corp.	\$ (884)	\$ (72,579)

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Statement of Equity

(thousands of Canadian dollars)
For the three months ended March 31, 2017

Algonquin Power & Utilities Corp. Shareholders							
	Common shares	Preferred shares	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non- controlling interests	Total
Balance, December 31, 2016	\$ 1,972,203	\$ 213,805	\$ 38,652	\$ (556,024)	\$ 254,927	\$ 562,358	\$ 2,485,921
Net earnings (loss)	—	—	—	25,959	—	(20,473)	5,486
Redeemable non- controlling interests not included in equity (note 15)	—	—	—	—	—	3,549	3,549
Other comprehensive loss	—	—	—	—	(26,843)	(4,648)	(31,491)
Dividends declared and distributions to non-controlling interests	—	—	—	(53,231)	—	(1,135)	(54,366)
Dividends and issuance of shares under dividend reinvestment plan	8,765	—	—	(8,765)	—	—	—
Common shares issued upon conversion of convertible debentures	1,110,610	—	—	—	—	—	1,110,610
Common shares issued pursuant to share-based awards (note 11(b))	18,310	—	(6,369)	(1,946)	—	—	9,995
Share-based compensation	—	—	2,355	—	—	—	2,355
Contributions received from non-controlling interests	—	—	—	—	—	21,734	21,734
Balance, March 31, 2017	\$ 3,109,888	\$ 213,805	\$ 34,638	\$ (594,007)	\$ 228,084	\$ 561,385	\$ 3,553,793

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Statements of Cash Flows

(thousands of Canadian dollars)

Three Months Ended March 31
2017 2016

Cash provided by (used in):			
Operating Activities			
Net earnings	\$	5,486	\$ 30,292
Adjustments and items not affecting cash:			
Depreciation and amortization		90,011	51,841
Deferred taxes		16,788	15,946
Unrealized loss (gain) on derivative financial instruments		2,363	(5,278)
Share-based compensation expense		2,355	1,073
Cost of equity funds used for construction purposes		(549)	(497)
Pension and post-employment expense		13,939	2,158
Non-cash revenue and other income		(272)	(1,590)
Write-down of long-lived assets		—	6,185
Changes in non-cash operating items (note 20)		(46,297)	(46,699)
		83,824	53,431
Financing Activities			
Increase in long-term debt		1,281,461	352,295
Decrease in long-term debt		(1,924,342)	(24,444)
Issuance of convertible debentures, net of costs		743,908	357,950
Cash dividends on common shares		(29,956)	(32,607)
Cash dividends on preferred shares		(2,600)	(2,600)
Cash contributions from non-controlling interests		53,405	—
Production-based cash contributions from non-controlling interest		9,124	9,454
Cash distributions to non-controlling interests		(206)	(1,842)
Issuance of common shares, net of costs		48	269
Proceeds from exercise of share options		12,761	19,493
Shares surrendered to fund withholding taxes on exercised share options		—	(5,218)
Increase in other long-term liabilities		9,608	3,834
Decrease in other long-term liabilities		(3,575)	(2,265)
		149,636	674,319
Investing Activities			
Decrease in restricted cash		2,006,151	4,542
Acquisitions of operating entities		(2,047,401)	(333,084)
Additions to property, plant and equipment		(201,769)	(80,905)
Increase in other assets		(737)	(11,221)
Distributions received in excess of equity income		(1,360)	(2,766)
Receipt of principal on notes receivable		—	11,690
Increase in long-term investments		(19,894)	(114,212)
		(265,010)	(525,956)
Effect of exchange rate differences on cash		(1,125)	(17,029)
Increase (decrease) in cash and cash equivalents		(32,675)	184,765
Cash and cash equivalents, beginning of period		110,417	124,353
Cash and cash equivalents, end of period	\$	77,742	\$ 309,118
Supplemental disclosure of cash flow information:		2017	2016
Cash paid during the period for interest expense	\$	63,826	\$ 28,857
Cash paid during the period for income taxes	\$	1,765	\$ 6,908
Non-cash financing and investing activities:			
Property, plant and equipment acquisitions in accruals	\$	106,329	\$ 16,507
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	\$	10,291	\$ 3,336
Issuance of common shares upon conversion of convertible debentures (note 10)	\$	1,098,355	\$ —

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2017 and 2016

(in thousands of Canadian dollars, except as noted and per share amounts)

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's operations are organized across two primary North American business units consisting of the Liberty Power Group and the Liberty Utilities Group. The Liberty Power Group owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets; the Liberty Utilities Group owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations.

1. Significant accounting policies

(a) Basis of preparation

The accompanying unaudited interim consolidated financial statements and notes have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP") and Article 10 of Regulation S-X provided by the U.S. Securities and Exchange Commission ("SEC"). In the opinion of management, the unaudited interim consolidated financial statements include all adjustments that are of a recurring nature and necessary for a fair presentation of the results of interim operations.

The significant accounting policies applied to these unaudited interim consolidated financial statements of APUC are consistent with those disclosed in the consolidated financial statements of APUC for the year ended December 31, 2016 except for adopted accounting policies described in note 2(a).

Effective January 1, 2017, the acquisition date, the unaudited consolidated results of The Empire District Electric Company ("Empire") are consolidated within APUC (note 3(a)). Empire's accounting policies align with those used by APUC's except certain Empire-specific policies including policies approved by the regulator as described below.

(b) Seasonality

APUC's operating results are subject to seasonal fluctuations that could materially impact quarter-to-quarter operating results and, thus, one quarter's operating results are not necessarily indicative of a subsequent quarter's operating results. APUC's hydroelectric energy assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally slower, while during the spring and fall periods flows are heavier. For APUC's wind energy assets, wind resources is typically stronger in spring, fall and winter and weaker in summer. APUC's solar energy assets experience greater insolation in summer, weaker in winter. APUC's water and wastewater utility assets' revenues fluctuate depending on the demand for water. During drier, hotter periods of the year, which occurs generally in the summer, demand for water is typically higher than during cooler, wetter periods of the year. During the winter period, natural gas distribution utilities experience higher demand than during the summer period. Where decoupling mechanisms exist, total volumetric revenue is prescribed by the Regulator and fluctuates based on usage while total fixed revenue will not fluctuate through the year. Different electrical distribution utilities can experience higher or lower demand in the summer or winter depending on the specific regional weather, industry characteristics and existence of a decoupling mechanism.

(c) Commonly owned facilities

Empire owns undivided interests in three electric generating facilities with ownership interest ranging from 7.52% to 60% with a corresponding share of capacity and generation from the facility used to serve Empire's customers. Empire's investment in the undivided interest is recorded as plant in service and recovered through rate base. Empire's share of operating costs are recognized in operating, maintenance and fuel expenditures excluding depreciation expense.

As at March 31, 2017 the following amounts related to commonly owned facilities were recognized in the unaudited interim consolidated financial statements:

Cost of ownership in plant in service	\$ 871,115
Accumulated Depreciation	\$ 230,777
Expenditures	\$ 26,819

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

The FASB issued ASU 2016-17 Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control. This update amends the consolidation guidance on how a reporting entity that is the single decision maker of a VIE should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. The adoption of this update in the first quarter of 2017 had no impact on the Company's unaudited interim consolidated financial statements.

The FASB issued ASU 2016-09, Compensation - Stock Compensation (Topic 718), to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of this update in the first quarter of 2017 had no material impact on the Company's unaudited interim consolidated financial statements. The Company continues to record the stock-based compensation expense adjusted for estimated forfeitures.

The FASB issued ASU 2016-06, Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments, to clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts, which is one of the criteria for bifurcating an embedded derivative. An entity performing the assessment under the amendments in this Update is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The adoption of this update in the first quarter of 2017 had no impact on the Company's unaudited interim consolidated financial statements.

The FASB issued ASU 2016-05, Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships, to clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument does not, in and of itself, require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue to be met. The adoption of this update in the first quarter of 2017 had no impact on the Company's unaudited interim consolidated financial statements.

The FASB issued ASU 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory, to simplify the subsequent measurement of inventory by replacing the current lower of cost and market test with a lower of cost and net realizable value test. The adoption of this update in the first quarter of 2017 had no impact on the Company's unaudited interim consolidated financial statements.

(b) Recently issued accounting guidance not yet adopted

The FASB issued ASU 2017-07 Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, to improve the reporting of defined benefit pension cost and postretirement benefit cost (net benefit cost) in the financial statements. This update requires the service cost component to be reported in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The update will also only allow the service cost component to be eligible for capitalization when applicable. The update is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. The adoption of the presentation component of the standard will change the presentation of net benefit cost in the Company's consolidated statements of operations. The Company is currently in the process of evaluating the impact of adoption of this standard on the eligibility for capitalization of the other components of net benefit cost on its consolidated financial statements, given the application of ASC 980 Regulated Operations and ongoing regulatory developments.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2017 and 2016

(in thousands of Canadian dollars, except as noted and per share amounts)

2. Recently issued accounting pronouncements (continued)**(b) Recently issued accounting guidance not yet adopted (continued)**

The FASB issued ASU 2017-05 Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets. The update clarifies the scope of the standard as well as provides additional guidance on partial sales of nonfinancial assets. The update is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted however the update must be adopted at the same time as ASU 2014-09. The Company is currently in the process of evaluating the impact of adoption of this update on its consolidated financial statements.

The FASB issued a new revenue recognition standard codified as ASC 606, Revenue from Contracts with Customers. This newly issued accounting standard provides accounting guidance for all revenue arising from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers unless the contracts are in the scope of other U.S. GAAP requirements, such as the leasing literature. The core principal of the new accounting guidance is that an entity should recognize revenue when it transfers 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 or services. ASC 606 will also require significantly expanded disclosures regarding the qualitative and quantitative information of the Company's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. This new revenue standard is required to be applied for fiscal years and interim periods beginning after December 15, 2017 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company has not elected to early adopt. The Company has identified existing customer contracts and tariffs that are within the scope of the new guidance and has in the process of conducting an assessment in order to determine the method of adoption and the impact it may have on its consolidated financial statements. The Company also closely monitors outstanding industry specific interpretative issues, including contributions in aid of construction and collectability of sales to low income customers.

3. Business acquisitions and development projects**(a) Acquisition of Empire**

On January 1, 2017, the Company completed the acquisition of Empire, a Joplin, Missouri based regulated electric, gas and water utility, serving customers in Missouri, Kansas, Oklahoma and Arkansas.

The purchase price of approximately U.S. \$2,414,000 for the acquisition of Empire consists of cash payments to Empire shareholders of U.S. \$34.00 per common share and the assumption of approximately U.S. \$855,000 of debt. The cash payment was funded with the acquisition facility for an amount of U.S. \$1,336,440 (note 7(b)), proceeds received from the initial instalment of convertible debentures (note 10) and an existing credit facility. The costs related to the acquisition have been expensed through the consolidated statements of operations.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

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*(in thousands of Canadian dollars, except as noted and per share amounts)***3. Business acquisitions and development projects (continued)****(a) Acquisition of Empire (continued)**

The following table summarizes the preliminary allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	\$ 52,594
Property, plant and equipment	2,763,612
Goodwill	1,001,570
Regulatory assets	258,143
Other assets	50,750
Long-term debt	(1,218,563)
Regulatory liabilities	(104,896)
Pension and other post-employment benefits	(107,907)
Deferred income tax liability, net	(569,358)
Other liabilities	(103,320)
Total net assets acquired	\$ 2,022,625
Cash and cash equivalent	\$ 2,338
Total net assets acquired, net of cash and cash equivalent	\$ 2,020,287

The determination of the fair value of assets acquired and liabilities assumed is based upon management's preliminary estimates and certain assumptions. Due to the timing of the acquisition, the Company has not completed the fair value measurements, particularly the relative fair value of each of the individual utilities acquired. The Company will continue to review information and perform further analysis prior to finalizing the fair value of the consideration paid and the fair value of the assets acquired and liabilities assumed.

Goodwill represents the excess of the purchase price over the aggregate fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include future growth, potential synergies and cost savings in the delivery of certain shared administrative and other services.

Property, plant and equipment, exclusive of computer software, are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Empire's assets is 39 years.

The table below presents the unaudited consolidated pro forma revenue and net income for the three months ended March 31, 2017 and 2016, assuming the acquisition of Empire had occurred on January 1, 2016. Pro forma net income includes the impact of fair value adjustments incorporated in the preliminary purchase price allocation above and adjustments necessary to reflect the financing costs as if the acquisition had been financed on January 1, 2016. However, non-recurring acquisition-related expenses are excluded from net income.

	Three Months Ended March 31	
	2017	2016
Revenues	\$ 557,917	\$ 549,674
Net income attributable to common shareholders	\$ 80,598	\$ 66,549

This pro forma information does not purport to represent what the actual results of operations of the Company would have been had the acquisition occurred on this date nor does it purport to predict the results of operations for future periods.

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*(in thousands of Canadian dollars, except as noted and per share amounts)***3. Business acquisitions and development projects (continued)****(b) Luning Solar Facility**

On February 15, 2017, Luning Utilities (Luning Holdings) LLC (the “Luning Holdings”) obtained control of the Luning Solar Facility upon achieving commercial operation. Luning Holdings is owned by the Calpeco Electric System, a regulated electric distribution utility of the Company. The Luning Solar Facility is a 50MWac solar generating facility located in Mineral County, Nevada acquired for a total purchase price of U.S. \$110,856. The Class A tax equity investor funded approximately U.S. \$39,000 of the acquisition cost and will receive the majority of the tax attributes associated with the Luning Solar project.

The following table summarizes the preliminary allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	\$ 198
Property, plant and equipment	145,045
Asset retirement obligation	(714)
Non-controlling interest (tax equity)	(50,548)
Total net assets acquired	\$ 93,981

The determination of the fair value of assets acquired and liabilities assumed is based upon management's preliminary estimates and certain assumptions. Due to the timing of the acquisition, the Company has not completed the fair value measurements.

The Company accounts for this interest as “Redeemable non-controlling interest” outside of permanent equity on the consolidated balance sheets. Redemption is not considered probable as of March 31, 2017.

(c) Bakersfield II Solar Facility

On December 14, 2016, the Company completed construction and placed in service a 10 MWac solar powered generating facility located adjacent to the Company's 20 MWac Bakersfield I Solar Facility in Kern County, California (“Bakersfield II Solar Facility”). Commercial operations as defined by the power purchase agreement was reached on January 11, 2017.

The Bakersfield II Solar Facility is controlled by a subsidiary of APUC (the “Bakersfield II Partnership”). The Class A partnership units are owned by a third-party tax equity investor who funded U.S. \$2,454 on November 29, 2016 and approximately U.S. \$9,800 on February 28, 2017. Through its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project.

The Company accounts for this interest as “Non-controlling interest” on the consolidated balance sheets.

4. Accounts receivable

Accounts receivable as of March 31, 2017 include unbilled revenue of \$70,838 (December 31, 2016 - \$57,822) from the Company's regulated utilities. Accounts receivable as of March 31, 2017 are presented net of allowance for doubtful accounts of \$9,763 (December 31, 2016 - \$7,064).

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2017 and 2016

(in thousands of Canadian dollars, except as noted and per share amounts)

5. Regulatory matters

The Company's regulated utility operating companies are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting policies, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company's regulated utility operating companies are accounted for under the principles of ASC 980. Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenue or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate-setting process.

On January 1, 2017, the Company completed the acquisition of Empire, an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of its electric segment, Empire also provides water service to three towns in Missouri. The Empire District Gas Company a wholly owned subsidiary is engaged in the distribution of natural gas in Missouri. These businesses are subject to regulation by the Missouri Public Service Commission, the State Corporation Commission of the State of Kansas, the Corporation Commission of Oklahoma, the Arkansas Public Service Commission and the Federal Energy Regulatory Commission. In general, the commissions set rates at a level that allows the utilities to collect total revenues or revenue requirements equal to the cost of providing service, plus an appropriate return on invested capital.

At any given time, the Company can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the consolidated financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period.

Subsequent to quarter-end, in April 2017, the Massachusetts Department of Public Utilities approved a rate increase of U.S. \$2,928 for the New England Natural Gas Company, for its 2017 gas system enhancement plan. The rates are effective May 1, 2017.

Subsequent to quarter-end, in April 2017, the State of Iowa Department of Commerce Utilities Board approved a rate increase of U.S. \$987 for Midstates Natural Gas. New rates are expected to be effective either June or July 2017.

In June 2016, the New Hampshire Public Utility Commission approved a temporary annual rate increase for the Granite State Electric System of U.S. \$2,355, effective July 1, 2016. Subsequent to quarter-end, on April 12, 2017, the New Hampshire Public Utility Commission approved a Final Order of a total U.S. \$3,750 annual revenue increase retroactive to July 1, 2016, and a U.S. \$2,474 step adjustment for plant additions made in 2016, effective May 1, 2017. In March 2017, the Arizona Corporate Commission approved a rate increase of U.S. \$152 for Entrada Del Oro Sewer, effective April 1, 2017.

On January 31, 2017, the Georgia Public Service Commission approved a Final Order for the Peach State Gas System of a U.S. \$686 annual revenue increase effective February 1, 2017.

Algonquin Power & Utilities Corp.

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*(in thousands of Canadian dollars, except as noted and per share amounts)***5. Regulatory matters (continued)**

Regulatory assets and liabilities consist of the following:

	March 31, 2017	December 31, 2016
Regulatory assets		
Environmental remediation	\$ 104,063	\$ 104,160
Pension and post-employment benefits	141,927	75,527
Debt premium	102,562	25,173
Fuel and commodity costs adjustments	14,197	6,972
Rate adjustment mechanism	27,997	40,602
Clean Energy and other customer programs	24,645	2,106
Deferred construction costs (a)	19,372	—
Asset retirement	18,870	2,113
Income taxes	36,195	10,182
Rate case costs	14,022	8,572
Other	34,193	16,557
Total regulatory assets	\$ 538,043	\$ 291,964
Less current regulatory assets	(62,674)	(48,440)
Non-current regulatory assets	\$ 475,369	\$ 243,524
Regulatory liabilities		
Cost of removal	\$ 159,737	\$ 110,330
Rate-base offset	19,948	20,946
Fuel and commodity costs adjustments	35,807	33,891
Deferred compensation received in relation to lost production	14,781	—
Deferred construction costs -fuel related (a)	9,990	—
Pension and post-employment benefits	8,065	5,481
Income Taxes	7,136	1,501
Other	13,575	10,585
Total regulatory liabilities	\$ 269,039	\$ 182,734
Less current regulatory liabilities	(51,159)	(47,769)
Non-current regulatory liabilities	\$ 217,880	\$ 134,965

- (a) Deferred construction costs reflects deferred costs from Empire's 2005 regulatory plan related to construction costs and fuel related costs of specific generating facilities. These amounts are being recovered over the life of the plants.

Algonquin Power & Utilities Corp.

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*(in thousands of Canadian dollars, except as noted and per share amounts)***6. Long-term investments**

Long-term investments consist of the following:

	March 31, 2017	December 31, 2016
Equity-method investees		
Red Lily	24,215	23,504
Deerfield Wind Project (a)	—	34,727
Amherst Island Wind Project	763	558
Other	6,020	5,630
	\$ 30,998	\$ 64,419
Notes receivable		
Development loans (b)	\$ 49,616	\$ 32,125
Other	6,034	6,058
	55,650	38,183
Available-for-sale investment	169	169
Other investments	2,641	2,662
Total long-term investments	\$ 89,458	\$ 105,433

(a) Deerfield Wind Project

Up to March 14, 2017, the Company held a 50% equity interest in Deerfield Wind SponsorCo LLC ("Deerfield SponsorCo"), which indirectly owns a 150 MW construction-stage wind development project ("Deerfield Wind Project") in the state of Michigan.

On October 12, 2016, third-party construction loan financing was provided to the Deerfield Wind Project in the amount of U.S. \$262,900 and a tax equity contribution agreement was executed. Construction was completed during the quarter and sale of power to the utility under the power purchase agreement started on February 21, 2017. Subsequent to quarter-end, on May 10, 2017, tax equity funding of U.S. \$166,595 was received.

On March 14, 2017, the Company acquired the remaining 50% interest in Deerfield SponsorCo for U.S. \$21,585 and as a result, obtained control of the facility. The Company accounted for the business combination using the acquisition method of accounting which requires that the fair value of assets acquired and liabilities assumed in the subsidiary be recognized on the consolidated balance sheet as of the acquisition date. It further requires that pre-existing relationships such as the existing development loan between the two parties (note 6(b)) and prior investments of business combinations achieved in stages also be remeasured at fair value. An income approach was used to value these items. A net gain of \$nil was recorded on acquisition.

The following table summarizes the preliminary allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	\$ (14,551)
Property, plant and equipment	442,086
Construction loan	(352,666)
Asset retirement obligation	(2,816)
Deferred revenue	(1,556)
Deferred tax liability	(1,979)
Net assets acquired	\$ 68,518
Cash and cash equivalent	4,183
Net assets acquired, net of cash and cash equivalent	\$ 64,335

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2017 and 2016

*(in thousands of Canadian dollars, except as noted and per share amounts)***6. Long-term investments (continued)****(b) Development loans**

As at March 31, 2017, the Company has a loan and credit support facility with Windlectric. During construction, the Company provides Windlectric with cash advances and credit support (in the form of letters of credit, escrowed cash, or guarantees) in amounts necessary for the continued development and construction of the Wind Projects. The loan bears interest at an annual rate of 10% on outstanding principal amount and matures on December 31, 2018.

As of December 31, 2016, the Company had outstanding loans of U.S. \$1,789 from Deerfield SponsorCo. Following acquisition of control of Deerfield SponsorCo LLC (note 6(a)), amounts advanced to the Deerfield Wind Project were eliminated on consolidation. The effects of foreign currency exchange rate fluctuations on these advances of a long-term investment nature are recorded in other comprehensive income effective March 14, 2017.

No interest revenue was accrued on the loans due to insufficient collateral in the Joint Ventures.

7. Long-term debt

Long-term debt consists of the following:

Borrowing type	March 31, 2017	December 31, 2016
Senior Unsecured Revolving Credit Facilities (a)	\$ 233,087	\$ 242,947
Senior Unsecured Bank Credit Facilities (b)	209,606	2,140,122
Canadian Dollar Borrowings		
Senior Unsecured Notes (c)	780,405	487,389
Senior Secured Project Notes	35,043	35,600
U.S. Dollar Borrowings		
Senior Unsecured Notes (d)	1,686,518	700,600
Senior Unsecured Utility Notes (e)	336,836	174,206
Senior Secured Utility Bonds (f)	1,137,923	132,551
Senior Secured Project Notes (g)	349,014	—
	\$ 4,768,432	\$ 3,913,415
Less: current portion	(20,066)	(10,075)
	\$ 4,748,366	\$ 3,903,340

Long-term debt issued at a subsidiary level relating to a specific operating facility is generally collateralized by the respective facility with no other recourse to the Company. Long-term debt whether or not collateralized have certain financial covenants, which must be maintained on a quarterly basis. Non-compliance with the covenants could restrict cash distributions/dividends to the Company from the specific facilities.

(a) Senior unsecured revolving credit facilities

In connection with the acquisition of Empire (note 3(a)), the Company assumed a U.S. \$200,000 5-year Credit Agreement which expires in October 2019, and includes two one-year extensions of the credit facility's maturity date. The Empire Facility is used primarily to provide credit support to Empire's commercial paper program.

Subsequent to quarter end, the Liberty Power Group entered into a \$150,000 bilateral revolving credit facility. The new facility matures on May 19, 2018.

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March 31, 2017 and 2016

(in thousands of Canadian dollars, except as noted and per share amounts)

7. Long-term debt (continued)

(b) Senior unsecured bank credit facilities

On December 30, 2016, in connection with the acquisition of Empire (note 3(a)), the Company drew U.S. \$1,336,440 from the acquisition facility it obtained from a syndicate of banks earlier in 2016. The funds drawn were transferred to a paying agent on December 30, 2016 for purposes of distribution to holders of the common shares of Empire (note 3(a)) on January 1, 2017. Following receipt of the Final Instalment from the convertible debentures on February 7, 2017 (note 10) and the senior notes financing on March 24, 2017 (note 7(d)), the Company fully repaid the acquisition Facility.

On March 24, 2016, the Company repaid U.S. \$100,000 of borrowings under the Corporate Term Facility with proceeds from the closing of the U.S. \$750,000 senior unsecured notes (notes 7(d)).

(c) Canadian dollar senior unsecured notes

On January 17, 2017, the Liberty Power Group issued \$300,000 senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of \$99.929 per \$100.00 principal amount.

(d) U.S. dollar senior unsecured notes

On March 24, 2017, Liberty Utilities Group's financing entity issued U.S. \$750,000 senior unsecured notes in six tranches. The proceeds were applied to repay the acquisition facility (note 7(b)) and other existing indebtedness. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%. In anticipation of the financing, the Liberty Utilities Group had entered into forward contracts to lock in the underlying U.S. Treasury interest rates. Considering the effect of the hedges, the effective weighted average rate paid by the Liberty Utilities Group will be 3.6%.

(e) U.S. dollar senior unsecured utility notes

On February 8, 2017, the U.S. \$707 Bella Vista Water unsecured utility notes were fully repaid.

On January 1, 2017, in connection with the acquisition of Empire (note 3(a)), the Company assumed U.S. \$102,000 in unsecured utility notes. The notes consist of two tranches, with maturities in 2033 and 2035 with coupons at 6.7% and 5.8%.

(f) U.S. dollar senior secured utility bonds

On January 1, 2017 in connection with the acquisition of Empire (note 3(a)), the Company assumed U.S. \$733,000 in secured utility notes. The bonds are secured by a first mortgage indenture and consist of ten tranches with maturities ranging between 2018 and 2044 with coupons ranging from 3.58% to 6.82%.

(g) U.S. dollar senior secured project notes

On March 14, 2017, in connection with the acquisition of Deerfield SponsorCo (note 6(a)), the Company assumed U.S. \$262,219 in construction loan. The loans bear interest at an annual rate of 2.33% on any outstanding principal amount. Subsequent to quarter-end on May 10, 2017, the construction loan was repaid from proceeds received from tax equity (note 6(a)) and cash contributions from APUC.

8. Pension and other post-employment benefits

In connection with the acquisition of Empire, the Company assumed pension and OPEB obligations of \$107,907. Empire District Electric provides the following plans to employees:

- A noncontributory defined benefit pension plan for all employees hired before January 1, 2014 meeting minimum age and service requirements.
- A cash balance defined benefit pension plan for all employees hired after January 1, 2014.
- A supplemental retirement program ("SERP") for designated officers of Empire. The SERP plan was frozen effective January 1, 2017.
- Certain healthcare and life insurance benefits to eligible retired employees, their dependents and survivors. Participants generally become eligible for retiree healthcare benefits after reaching age 55 with 5 years of service. Employees hired after January 1, 2014 are offered unsubsidized retiree healthcare benefits upon retirement.

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*(in thousands of Canadian dollars, except as noted and per share amounts)***8. Pension and other post-employment benefits (continued)**

The following table outlines the aggregate financial position for the key plans as at January 1, 2017:

	Pension benefits	SERP	OPEB
Projected benefit obligation	\$ 329,158	\$ 17,073	\$ 131,264
Fair value of Plan Assets	247,740	—	122,900
Unfunded status	\$ (81,418)	\$ (17,073)	\$ (8,364)

Empire has rate orders with Missouri, Kansas and Oklahoma allowing the recovery of pension costs. As a result, Empire records the Missouri, Kansas and Oklahoma portion of any costs above or below the amount included in rates as a regulatory asset or liability, respectively.

The following table lists the components of net benefit costs for the pension plans and other post-employment benefits ("OPEB") recorded as part of operating expenses in the unaudited interim consolidated statements of operations. The employee benefit costs related to businesses acquired are recorded in the unaudited interim consolidated statements of operations from the date of acquisition.

	Pension benefits		OPEB	
	Three Months Ended March 31		Three Months Ended March 31	
	2017	2016	2017	2016
Service cost	\$ 4,762	\$ 2,030	\$ 1,690	\$ 815
Interest cost	6,597	3,376	2,212	921
Expected return on plan assets	(8,345)	(3,512)	(2,143)	(319)
Amortization of net actuarial loss	354	656	(48)	131
Amortization of prior service credits	(206)	(151)	(87)	(477)
Amortization of regulatory asset/liability	3,522	1,142	171	267
Net benefit cost	\$ 6,684	\$ 3,541	\$ 1,795	\$ 1,338

9. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

	March 31, 2017	December 31, 2016
Advances in aid of construction	\$ 109,188	\$ 105,191
Environmental remediation obligations	65,835	63,378
Asset retirement obligations	61,000	24,822
Customer deposits	35,591	14,881
Unamortized investment tax credits	23,957	—
Hook up fees	13,204	12,039
Deferred income	1,538	—
Deferred credits	44,188	44,544
Other	31,781	10,751
	386,282	275,606
Less current portion	(67,411)	(43,157)
	\$ 318,871	\$ 232,449

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*(in thousands of Canadian dollars, except as noted and per share amounts)***9. Other long-term liabilities and deferred credits (continued)**

In connection with the acquisition of Empire, the Company assumed certain asset retirement obligations. Asset retirement obligations mainly relate to legal requirements to: (i) remove certain river water intake structures and equipment; (ii) disposal of coal combustion residuals and Polychlorinated Biphenyls (PCB) contaminants; and (iii) remove asbestos upon major renovation or demolition of structures and facilities.

As the cost of retirement of asset are expected to be recovered through rates, a corresponding regulatory asset is recorded, as well as the on-going liability accretion and asset depreciation expense.

In connection with the acquisition of Empire, the Company assumed investment tax credits based on the investment made in a generating station, which, if unused, will expire in 2030. Management expects to use these credits to offset future income tax liabilities. The tax credits will have no significant income statement impact because they will flow to customers as the tax credits are amortized over the life of the plant.

10. Convertible Unsecured Subordinated Debentures

Maturity date	March 31, 2026
Interest rate	5.00%
Conversion price per share	\$ 10.60
Carrying value at December 31, 2016	\$ 358,619
Receipt of Final instalment, net of deferred financing costs	743,908
Amortization of deferred financing costs	1,024
Conversion to common shares	\$ (1,098,355)
Carrying value at March 31, 2017	\$ 5,196
Face value at March 31, 2017	\$ 5,401

In March 2016, the Company completed the sale of \$1,150,000 aggregate principal amount of 5.0% convertible debentures.

The convertible debentures were sold on an instalment basis at a price of \$1,000 principal amount of debenture, of which \$333 was received on closing of the debenture offering and the remaining \$667 (the "Final Instalment") was received on February 2, 2017 ("Final Instalment Date") following satisfaction of conditions precedent to the closing of the acquisition of Empire (note 3(a)). The proceeds received from the initial and final instalments, net of financing costs were \$357,694 and \$743,908, respectively. As the Final Instalment Date occurred prior to the first anniversary of the closing of the debenture offering, holders of the convertible debentures who paid the final instalment by February 2, 2017 received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing the interest that would have accrued from the day following the Final Instalment Date up to and including March 1, 2017. The interest expense recorded for the three months ended March 31, 2017 is \$9,373 (2016 - \$4,884).

The debentures are convertible into up to 108,490,566 common shares. As at March 31, 2017, a total of 107,981,056 common shares of the Company were issued (note 11), representing conversion into common shares of more than 99.53% of the convertible debentures.

The remaining convertible debentures mature on March 31, 2026 and bear interest at an annual rate of 0% per \$1,000 principal amount of convertible debentures.

After the Final Instalment Date, any debentures not converted into common shares may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date. At maturity, the Company will have the right to pay the principal amount due in cash or in common shares. In the case of common shares, such shares will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

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*(in thousands of Canadian dollars, except as noted and per share amounts)***11. Shareholders' capital**

(a) Common shares

Number of common shares:

	2017
Common shares, beginning of year	274,087,018
Issuance of common shares upon conversion of convertible debentures (note 10)	107,981,056
Issuance of common shares upon exercise of share options, net of withholding taxes	1,469,362
Issuance of shares under the dividend reinvestment and employee share compensation plans	1,134,849
Common shares, end of period	384,672,285

(b) Share-based compensation

During the three months ended March 31, 2017, the Board of Directors of APUC (the "Board") approved the grant of 2,328,343 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of \$12.82, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2018, 2019, and 2020. Options may be exercised up to eight years following the date of grant.

The following assumptions were used in determining the fair value of share options granted:

Risk-free interest rate	1.42%
Expected volatility	25%
Expected dividend yield	4.25%
Expected life	5.5
Weighted average grant date fair value per option	\$ 1.45

In March 2017, executives of the Company exercised 1,469,362 stock options at a weighted average exercise price of \$7.81 in exchange for common shares issued from treasury and 165,139 options were settled at their cash value as payment for tax withholdings related to the exercise of the options.

In March 2017, 253,809 Performance Share Units ("PSU") were granted to executives of the Company. The PSUs vest on January 1, 2020. During the quarter, the Company settled 173,499 PSU in exchange for common shares issued from treasury and 182,463 PSUs were settled at their cash value as payment for tax withholdings related to the settlement of the PSUs.

During the three months ended March 31, 2017, 14,652 Deferred Share Units ("DSU") were issued pursuant to the election of the Directors to defer a percentage of their Directors' fee in the form of DSUs.

For the three months ended March 31, 2017, APUC recorded \$2,255 (2016 -\$1,010) in total share-based compensation expense. The compensation expense is recorded as part of administrative expenses in the unaudited interim consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As of March 31, 2017, total unrecognized compensation costs related to non-vested options and PSUs were \$6,051 and \$5,116, respectively, and are expected to be recognized over a period of 2.03 and 2.29 years, respectively.

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*(in thousands of Canadian dollars, except as noted and per share amounts)***12. Accumulated Other comprehensive income (loss)**

AOCI consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain on cash flow hedges	Net change on available- for-sale investments	Pension and post- employment actuarial changes	Total
Balance, January 1, 2016	\$ 261,357	\$ 39,329	\$ (72)	\$ (13,877)	\$ 286,737
OCI (loss) before reclassifications	(61,029)	34,308	213	1,648	(24,860)
Amounts reclassified	—	(7,554)	—	604	(6,950)
Net current period OCI	(61,029)	26,754	213	2,252	(31,810)
Balance, December 31, 2016	\$ 200,328	\$ 66,083	\$ 141	\$ (11,625)	\$ 254,927
OCI (loss) before reclassifications	(32,133)	7,509	2	—	(24,622)
Amounts reclassified	—	(2,277)	—	56	(2,221)
Net current period OCI	\$ (32,133)	\$ 5,232	\$ 2	\$ 56	\$ (26,843)
Balance, March 31, 2017	\$ 168,195	\$ 71,315	\$ 143	\$ (11,569)	\$ 228,084

Amounts reclassified from AOCI for unrealized gain (loss) on cash flow hedges affected revenue from non-regulated energy sales and interest expense while those for pension and post-employment actuarial changes affected administrative expenses.

13. Dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. The Company declares and pays the dividend on its common shares in U.S. dollars. Dividends declared in Canadian equivalent dollars during the quarter were as follows:

	Three Months Ended March 31			
	2017		2016	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	\$ 59,395	\$ 0.1533	\$ 34,960	\$ 0.1287
Series A preferred shares	\$ 1,350	\$ 0.2813	\$ 1,350	\$ 0.2813
Series D preferred shares	\$ 1,250	\$ 0.3125	\$ 1,250	\$ 0.3125

14. Related party transactions*Emera Inc.*

A member of the Board of APUC is an executive at Emera. During the three months ended March 31, 2017, the Energy Services Business sold electricity to Maine Public Service Company and Bangor Hydro, both of which are subsidiaries of Emera, amounting to U.S. \$2,981 (2016 - U.S. \$2,606). During the three months ended March 31, 2017, the Liberty Utilities Group purchased natural gas amounting to U.S. \$877 (2016 - U.S. \$1,913) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction. In 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply, and construction agreement for the Tinker transmission upgrade project. The transmission upgrade was placed in service in April 2017 with final completion of the contract work expected in June 2017. The total cost of the contract is estimated at \$8,809. The contract followed a market based request for proposal process.

There was U.S. \$2,576 included in accruals for the three months ended March 31, 2017 (2016 - U.S. \$261) related to these transactions.

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*(in thousands of Canadian dollars, except as noted and per share amounts)***14. Related party transactions (continued)***Equity-method investments*

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees \$439 (2016 - \$748) during the three months ended March 31, 2017.

Trafalgar

In 2016, the Company received U.S. \$10,083 in proceeds from the settlement of the Trafalgar matter, and paid U.S. \$2,900 to an entity partially and indirectly owned by Senior Executives as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. \$6,600 was recorded in 2016.

Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction is expected to be settled in 2017.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

15. Non-controlling interests and Redeemable non-controlling interest

Net loss attributable to non-controlling interests for the three months ended March 31 consists of the following:

	2017	2016
HLBV and other adjustments attributable to:		
Non-controlling interest -Class A partnership units	\$ (17,985)	\$ (12,043)
Non-controlling interest -redeemable Class A partnership units	(3,549)	(1,388)
Other net earnings attributable to non-controlling interests	1,061	1,687
Net effect of non-controlling interests	\$ (20,473)	\$ (11,744)

16. Income taxes

For the three months ended March 31, 2017, the Company's overall effective tax rate was different from the statutory rate of 26.50% (2016 - 26.50%) due primarily to higher tax rates in U.S. subsidiaries, non-controlling interest partner's tax expenses, inter-corporate dividends and non-deductible expenses.

17. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares and subscription receipts outstanding in 2016. Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts outstanding in 2016, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs and DSUs outstanding during the year and, if dilutive, potential incremental common shares resulting from the application of the treasury stock method to outstanding share options. The convertible debentures (note 10) are convertible into common shares at any time after the Final Instalment Date, but prior to maturity or redemption by the Company. The Final Instalment Date occurred on February 2, 2017, and as such, the shares issuable upon conversion of the convertible debentures are included in diluted earnings per share beginning on that date.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

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*(in thousands of Canadian dollars, except as noted and per share amounts)***17. Basic and diluted net earnings per share (continued)**

The reconciliation of the net earnings and the weighted average shares used in the computation of basic and diluted earnings per share for the three months ended March 31 are as follows:

	2017	2016
Net earnings attributable to shareholders of APUC	\$ 25,959	\$ 42,036
Series A Preferred shares dividend	1,350	1,350
Series D Preferred shares dividend	1,250	1,250
Net earnings attributable to common shareholders of APUC – Basic and Diluted	\$ 23,359	\$ 39,436
Weighted average number of shares		
Basic	343,549,831	268,565,782
Effect of dilutive securities	3,102,922	3,566,763
Diluted	346,652,753	272,132,545

The shares potentially issuable as a result of 1,129,168 share options (2016 - 3,937,340) are excluded from this calculation as they are anti-dilutive.

18. Segmented information

In connection with the acquisition of Empire on January 1, 2017, the Company aligned its management reporting under two primary North American business units consisting of the Liberty Power Group and the Liberty Utilities Group. The two business units are the two segments of the Company.

The Liberty Power Group owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the Liberty Utilities Group owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations.

For purposes of evaluating divisional performance, the Company allocates the realized portion of any gains or losses on financial instruments to specific divisions. The unrealized portion of any gains or losses on derivative instruments not designated in a hedging relationship is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The results of operations and assets for these segments are reflected in the tables below. The results of operations and assets for these new segments are reflected in the tables below. The comparative information for 2016 has been reclassified to conform with the composition of the reporting segments presented in the current year.

Algonquin Power & Utilities Corp.

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*(in thousands of Canadian dollars, except as noted and per share amounts)***18. Segmented information (continued)**

Three Months Ended March 31, 2017				
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	\$ 76,702	\$ 481,215	\$ —	\$ 557,917
Fuel, power and water purchased	7,305	156,377	—	163,682
Net revenue	69,397	324,838	—	394,235
Operating expenses	19,199	129,678	—	148,877
Administrative expenses	4,293	9,466	889	14,648
Depreciation and amortization	26,195	56,176	334	82,705
Gain on foreign exchange	—	—	80	80
Operating income (loss) from continuing operations	19,710	129,518	(1,303)	147,925
Interest expense	11,058	27,415	26,089	64,562
Interest, dividend, equity and other income	(1,220)	(1,321)	(740)	(3,281)
Other expenses (gain)	1,589	(183)	60,380	61,786
Earnings (loss) before income taxes	\$ 8,283	\$ 103,607	\$ (87,032)	\$ 24,858
Property, plant and equipment	\$2,896,605	\$ 5,258,224	\$ 44,230	\$ 8,199,059
Equity-method investees	25,230	1,064	4,704	30,998
Total assets	3,213,853	7,563,965	102,873	10,880,691
Capital expenditures	19,026	182,743	—	201,769
Three Months Ended March 31, 2016				
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	\$ 72,362	\$ 269,383	\$ —	\$ 341,745
Fuel and power purchased	5,615	106,719	—	112,334
Net revenue	66,747	162,664	—	229,411
Operating expenses	16,280	68,822	—	85,102
Administrative expenses	4,905	5,430	1,083	11,418
Depreciation and amortization	21,388	27,999	338	49,725
Gain on foreign exchange	—	—	(302)	(302)
	24,174	60,413	(1,119)	83,468
Interest expense	5,943	12,738	6,382	25,063
Interest, dividend and other income	(514)	(1,220)	(862)	(2,596)
Other expense (gain)	289	6,048	5,868	12,205
Earnings (loss) before income taxes	\$ 18,456	\$ 42,847	\$ (12,507)	\$ 48,796
Capital expenditures	42,396	38,509	—	80,905
December 31, 2016				
Property, plant and equipment	\$2,455,336	\$ 2,390,047	\$ 44,563	\$4,889,946
Equity-method investees	59,021	914	4,484	64,419
Total assets	2,771,651	5,388,966	88,843	8,249,460

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Notes to the Unaudited Interim Consolidated Financial Statements

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(in thousands of Canadian dollars, except as noted and per share amounts)

19. Commitments and contingencies

(a) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements. Accruals for any contingencies related to these items are recorded in the unaudited interim consolidated financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

Empire is subject to various federal, state, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials or other wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as remediation of contaminated sites and other environmental matters. Management believes that operations are in material compliance with present environmental laws and regulations. Currently it is not possible to accurately estimate compliance costs for any new requirements, it is expected that these costs might be material, although recoverable in rates.

Condemnation Expropriation Proceedings

Mountain Water is currently the subject of a condemnation lawsuit filed by the city of Missoula. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision that the city of Missoula can proceed with condemnation of Mountain Water's assets. Upon taking possession of Mountain Water's assets, the compensation to be paid by the city of Missoula for such taking will be the value of the utility (determined by the valuation commissioners on November 17, 2015 to be U.S. \$88,600 as of May 6, 2014). Mountain Water is expected to receive certain additional amounts that may include legal fees, interest, post-valuation capital expenditures and property tax reimbursement.

On December 22, 2015, various developers filed a lawsuit in Missoula County District Court against Mountain Water and the city of Missoula. The lawsuit pertains to Funded By Other (FBO) contracts between each developer and Mountain Water. Under these FBO contracts, the developers paid for facilities to provide water service and Mountain Water agreed to refund such amounts over a 40 year period. As of the date of acquisition of Western Water Holdings, the outstanding balance of these advances, on a non-discounted basis, was U.S. \$23,108. On February 21, 2017, the court issued an order imposing equitable liens on the Mountain Water assets that are the subject of the FBO contracts, mandating that the liens be satisfied directly from the condemnation award, if and when paid.

On April 27, 2017, Mountain Water agreed in principle to certain terms with the City of Missoula relating to the condemnation of Mountain Water's assets. The city is expected to take possession of Mountain Water's assets in the second quarter or early in the third quarter of 2017.

Subject to final adjustments, APUC expects that the net effect of the foregoing and terms of the original acquisition of Mountain Water will result in Liberty Utilities receiving an amount of approximately U.S. \$103,000 from the disposition of the utility.

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 6, the following significant commitments exist as of March 31, 2017.

APUC has outstanding purchase commitments for power purchases, gas delivery, service and supply, service agreements, capital project commitments and operating leases.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2017 and 2016

*(in thousands of Canadian dollars, except as noted and per share amounts)***19. Commitments and contingencies (continued)**

(b) Commitments (continued)

Detailed below are estimates of future commitments under these arrangements:

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Power purchase (i)	\$ 64,410	\$ 50,569	\$ 51,831	\$ 53,058	\$ 40,572	\$ 281,236	\$ 541,676
Gas supply and service agreements (ii)	105,279	83,306	65,819	41,311	33,538	109,696	438,949
Service agreements	46,184	46,532	48,671	50,676	51,218	493,522	736,803
Capital projects	68,665	19,367	69	69	69	17	88,256
Operating leases	10,502	10,191	9,407	8,930	8,995	246,954	294,979
Total	\$295,040	\$209,965	\$175,797	\$154,044	\$134,392	\$1,131,425	\$2,100,663

- (i) Power purchase: APUC's electric distribution facilities have commitments to purchase physical quantities of power for load serving requirements. The commitment amounts included in the table above which are based on market prices were reflected using the March 31, 2017 prices. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.
- (ii) Gas supply and service agreements: APUC's gas distribution facilities and thermal generation facilities have commitments to purchase physical quantities of natural gas under contracts for purposes of load serving requirements and of generating power.

20. Non-cash operating items

The changes in non-cash operating items consist of the following:

	Three Months Ended March 31	
	2017	2016
Accounts receivable	\$ 13,193	\$ 13,619
Fuel and natural gas in storage	11,424	16,621
Supplies and consumable inventory	(1,060)	310
Income taxes receivable	(1,133)	(3,762)
Prepaid expenses	(1,120)	(3,972)
Accounts payable	(85,300)	(35,706)
Accrued liabilities	25,440	(36,199)
Current income tax liability	977	(604)
Net regulatory assets and liabilities	(8,718)	2,994
	\$ (46,297)	\$ (46,699)

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

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*(in thousands of Canadian dollars, except as noted and per share amounts)***21. Financial instruments**

(a) Fair value of financial instruments

March 31, 2017	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	\$ 55,650	\$ 56,817	\$ —	\$ 56,817	\$ —
Derivative instruments:					
Energy contracts designated as a cash flow hedge	92,043	92,043	—	—	92,043
Currency forward contract not designated as a hedge	127	127	—	127	—
Commodity contracts for regulated operations	1,819	1,819	—	1,819	—
Transmission congestion rights	3,254	3,254	—	3,254	—
Total derivative instruments	97,243	97,243	—	5,200	92,043
Total financial assets	\$ 152,893	\$ 154,060	\$ —	\$ 62,017	\$ 92,043
Long-term debt	\$ 4,768,432	\$ 4,358,719	\$ 837,559	\$ 3,521,160	\$ —
Convertible debentures	5,196	5,401	5,401	—	—
Preferred shares, Series C	18,451	19,051	—	19,051	—
Derivative instruments:					
Cross-currency swap designated as a net investment hedge	102,232	102,232	—	102,232	—
Interest rate swap designated as a hedge	14,463	14,463	—	14,463	—
Commodity contracts for regulated operations	4,221	4,221	—	4,221	—
Total derivative instruments	120,916	120,916	—	120,916	—
Total financial liabilities	\$ 4,912,995	\$ 4,504,087	\$ 842,960	\$ 3,661,127	\$ —

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2017 and 2016

*(in thousands of Canadian dollars, except as noted and per share amounts)***21. Financial instruments (continued)**

(a) Fair value of financial instruments (continued)

December 31, 2016	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	\$ 38,183	\$ 47,933	\$ —	\$ 47,933	\$ —
Derivative instruments ⁽¹⁾ :					
Energy contracts designated as a cash flow hedge	84,554	84,554	—	—	84,554
Interest rate swap designated as a hedge	48,093	48,093	—	48,093	—
Currency forward contract not designated as a hedge	17,864	17,864	—	17,864	—
Commodity contracts for regulatory operations	359	359	—	359	—
Total derivative instruments	150,870	150,870	—	66,316	84,554
Total financial assets	\$ 189,053	\$ 198,803	\$ —	\$ 114,249	\$ 84,554
Long-term debt	\$ 3,913,415	\$ 3,999,266	\$ 517,637	\$ 3,481,629	\$ —
Convertible debentures	358,619	455,975	455,975	—	—
Preferred shares, Series C	18,460	18,613	—	18,613	—
Derivative instruments:					
Cross-currency swap designated as a net investment hedge	95,404	95,404	—	95,404	—
Interest rate swap designated as a hedge	13,385	13,385	—	13,385	—
Commodity contracts for regulated operations	36	36	—	36	—
Total derivative instruments	108,825	108,825	—	108,825	—
Total financial liabilities	\$ 4,399,319	\$ 4,582,679	\$ 973,612	\$ 3,609,067	\$ —

(1) Balance of \$314 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2017 and 2016

*(in thousands of Canadian dollars, except as noted and per share amounts)***21. Financial instruments (continued)****(a) Fair value of financial instruments (continued)**

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value as of March 31, 2017 and December 31, 2016 due to the short-term maturity of these instruments.

Notes receivable fair values (level 2) have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management.

The Company's level 2 fair value of long-term debt at fixed interest rates and Series C preferred shares has been determined using a discounted cash flow method and current interest rates.

The Company's level 2 fair value derivative instruments primarily consist of swaps, options, rights and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace.

The Company's level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from \$23.16 to \$117.87 with a weighted average of \$34.94 as of March 31, 2017. The processes and methods of measurement are developed using the market knowledge of the trading operations within the Company and are derived from observable energy curves adjusted to reflect the illiquid market of the hedges and, in some cases, the variability in deliverable energy. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts is detailed in notes 21(b)(ii) and 21(b)(iv).

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the three months ended March 31, 2017 and 2016.

(b) Derivative instruments

Derivative instruments are recognized on the unaudited interim consolidated balance sheets as either assets or liabilities and measured at fair value at each reporting period.

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas and electric service territories. The Company's strategy is to minimize fluctuations in gas sale prices to regulated customers.

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

	2017
Financial contracts: Swaps	922,308
Options	680,671
Forward contracts	17,390,000
	18,992,979

At March 31, 2017, transmission congestion rights ("TCR") of 2,033 monthly MWH have been obtained from TCR auctions to hedge 2017 congestion costs in the Southwest Power Pool ("SPP") Integrated Marketplace.

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March 31, 2017 and 2016

*(in thousands of Canadian dollars, except as noted and per share amounts)***21. Financial instruments (continued)**

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

The accounting for these derivative instruments is subject to guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the consolidated balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 5). As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact.

The following table presents the impact of the change in the fair value of the Company's natural gas derivative contracts had on the unaudited interim consolidated balance sheets:

	March 31, 2017	December 31, 2016
Regulatory assets:		
Swap contracts	U.S. \$ 1	U.S. \$ —
Option contracts	U.S. \$ 56	U.S. \$ 27
Forward contracts	U.S. \$ 3,650	U.S. \$ —
Regulatory liabilities:		
Swap contracts	U.S. \$ 25	U.S. \$ 175
Option contracts	U.S. \$ 9	U.S. \$ 92
Forward contracts	U.S. \$ 3,529	U.S. \$ —

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities by entering into the following long-term energy derivative contracts.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Pay floating price (per MW-hr)
648,647	December 2022	U.S. \$ 42.81	PJM Western HUB
2,783,176	December 2022	U.S. \$ 30.25	NI HUB
3,552,626	December 2027	U.S. \$ 36.46	ERCOT North HUB

On October 25, 2016, the Company entered into forward contracts to purchase U.S. \$250,000 10-year U.S. Treasury bills at an interest rate of 1.8395% and U.S. \$250,000 30-year U.S. Treasury bills at an interest rate of 2.5539% which settled on February 13, 2017 in order to reduce the interest rate risk related to the issuance of U.S. \$500,000 bonds in relation to the acquisition of Empire (note 7(d)). The change in fair value to February 13, 2017 resulted in a gain of U.S. \$36,677. The effective portion of the hedge of U.S. \$36,533 for the three months ended March 31, 2017 was recorded in OCI while the ineffective portion was recorded in the unaudited interim statement of operations.

The Company is party to a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year \$135,000 bond. The change in fair value resulted in a loss of \$1,079 for the three months ended March 31, 2017 (2016 - gain of \$14,425), which is recorded in OCI.

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*(in thousands of Canadian dollars, except as noted and per share amounts)***21. Financial instruments (continued)**

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The following table summarizes OCI attributable to derivative financial instruments designated as a cash flow hedge:

	Three months ended March 31	
	2017	2016
Effective portion of cash flow hedge, gain	\$ 7,518	\$ 25,134
Amortization of cash flow hedge	(9)	(10)
Gain reclassified from AOCI	(2,277)	(3,558)
OCI attributable to shareholders of APUC	\$ 5,232	\$ 21,566

The Company expects \$11,934 and \$2,093 of gains currently in AOCI to be reclassified into non-regulated energy sales and interest expense, respectively, within the next twelve months, as the underlying hedged transactions settle.

(iii) Foreign exchange hedge of net investment in foreign operation

The Company is exposed to currency fluctuations from its U.S. based operations. APUC manages this risk primarily through the use of natural hedges by using U.S. long-term debt to finance its U.S. operations and a combination of foreign exchange forward contracts and spot purchases. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

The Company designates the amounts drawn on the Liberty Power Group's revolving credit facility denominated in U.S. dollars in excess of the principal amount on the USD loans receivable from its equity investees as a hedge of the foreign currency exposure of its net investment in the Liberty Power Group's U.S. operations. The related foreign currency transaction gain or loss designated as, and effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A foreign currency loss of \$nil for the three months ended March 31, 2017 (2016 - \$nil) was recorded in OCI.

Concurrent with its \$150,000, \$200,000 and \$300,000 debenture offerings in December 2012, January 2014, and January 2017, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Generation Group's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. For the three months ended March 31, 2017, a loss of \$8,169 (2016 - \$1,236) was recorded in OCI.

(iv) Other derivatives

The Company provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Hydroelectric Facility are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated through the use of short-term financial forward energy purchase contracts which are classified as derivative instruments. The electricity derivative contracts are net settled fixed-for-floating swaps whereby APUC pays a fixed price and receives the floating or indexed price on a notional quantity of energy over the remainder of the contract term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

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(in thousands of Canadian dollars, except as noted and per share amounts)

21. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligation, including certain project specific debt and its revolving credit facilities, its interest rate swaps as well as interest earned on its cash on hand. The Company currently hedges some of that risk (note 21(b)(ii)).

The Company is exposed to foreign exchange fluctuations related to U.S dollar denominated development loans from projects accounted for as equity investments (note 6(b)). This risk was mitigated through the use of currency forward contracts to sell U.S. \$38,400 for \$47,225 between July 29, 2016 and September 29, 2016. As of March 31, 2017, these instruments had settled. This currency forward contract was not accounted for as a hedge.

The Company was exposed to foreign exchange fluctuations related to the acquisition of the Empire shares denominated in U.S dollar (note 3(a)). This risk was mitigated through the conversion to U.S. dollars of \$359,950 from the proceeds received on the initial instalment of convertible unsecured subordinated debentures (note 10) and the use of a currency forward contract to buy an amount of U.S. \$567,665 for \$744,050 on January 31, 2017. This currency forward contract was not accounted for as a hedge. The settlement of the currency forward contract resulted in a total realized gain of \$1,452 and a loss for the period of \$17,864, which is recorded as loss on foreign exchange in the unaudited interim consolidated statements of operations for the three months period ended March 31, 2017 (2016 - \$nil).

The Company is exposed to foreign exchange fluctuations related to the portion of its dividend declared and payable in U.S. dollars. This risk was mitigated through the use of a currency forward contract to buy U.S. \$25,000 for \$33,143 on April 17, 2017. As of March 31, 2017 this instrument had not settled, and resulted in an unrealized gain of \$127 which is recorded as a gain on derivative financial instruments in the unaudited interim consolidated statements of operations for the three months period ended March 31, 2017. This currency forward contract was not accounted for as a hedge.

For derivatives that are not designated as hedges and for the ineffective portion of gains and losses on derivatives that are accounted for as hedges, the changes in the fair value are immediately recognized in earnings.

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*(in thousands of Canadian dollars, except as noted and per share amounts)***21. Financial instruments (continued)**

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

The effects on the unaudited interim consolidated statements of operations of derivative financial instruments not designated as hedges consist of the following:

	Three Months Ended March 31	
	2017	2016
Change in unrealized gain on derivative financial instruments:		
Energy derivative contracts	\$ —	(426)
Currency forward contracts	—	(5,250)
Total change in unrealized gain on derivative financial instruments	\$ —	\$ (5,676)
Realized loss (gain) on derivative financial instruments:		
Interest rate swaps	(196)	—
Energy derivative contracts	730	970
Total realized loss on derivative financial instruments	\$ 534	\$ 970
Loss (gain) on derivative financial instruments not accounted for as hedges	534	(4,706)
Ineffective portion of derivative financial instruments accounted for as hedges	848	398
	\$ 1,382	\$ (4,308)
Amounts recognized in the consolidated statements of operations consist of:		
Loss on derivative financial instruments	\$ 1,382	\$ 942
Gain on foreign exchange	\$ —	\$ (5,250)
	\$ 1,382	\$ (4,308)

Effective May 1, 2016, the Company entered into a weather derivative contract as an economic hedge for revenue from its St. Leon I wind powered generating facility in the event the wind resource availability falls below a normal range. Non-exchange-traded options are accounted for using the intrinsic method. Changes in the intrinsic value of \$158 during the three months ended March 31, 2017 is reflected in non-regulated energy sales in the unaudited interim consolidated statement of operations. Premiums paid related to these weather derivative agreements are expensed over each respective contract period.

(c) Risk management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view of mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

22. Comparative figures

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted in the current year.

CORPORATE INFORMATION

DIRECTORS

Kenneth Moore, Chairman – Managing Partner, NewPoint Capital Partners Inc.

Christopher Ball – Executive Vice President, Corpfinance International Ltd.

Chris Jarratt – Vice Chair, Algonquin Power & Utilities Corp.

D. Randy Laney – Former Chairman of the Board, The Empire District Electric Company

Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.

Masheed Saidi – Former Executive VP and Chief Operating Officer, U.S. Transmission, Natural Grid USA

Dilek Samil – Former Executive VP and Chief Operating Officer, NV Energy

Melissa Stapleton Barnes – Senior VP, Enterprise Risk Management, and Chief Ethics and Compliance Officer, Eli Lilly and Company

George Steeves – Principal, True North Energy

THE EXECUTIVE TEAM

Ian Robertson, Chief Executive Officer

Chris Jarratt, Vice Chair

David Bronicheski, Chief Financial Officer

Linda Beairsto, Chief Compliance Officer

Jeff Norman, Chief Development Officer

David Pasieka, Chief Operations Officer, Liberty Utilities Group

Mike Snow, Chief Operations Officer, Liberty Power Group

Jennifer Tindale, Chief Legal Officer

George Trisic, Chief Administration Officer and Corporate Secretary

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U.S. TRANSFER AGENT

AST American Stock Transfer & Trust Company, LLC

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Brooklyn, New York, 11219

STOCK EXCHANGE

The Toronto Stock Exchange: AQN, AQN.PR.A, AQN.PR.D

The New York Stock Exchange: AQN

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