

ALGONQUIN

Q2 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 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 and six months ended June 30, 2017. The Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's Unaudited Interim Consolidated Financial Statements for the three and six months ended June 30, 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 August 10, 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 average exchange rate as at August 9, 2017, the quarterly dividend is equivalent to Cdn \$0.1480 per common share or Cdn \$0.5919 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 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 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.

Liberty Utilities Group

The Liberty Utilities Group operates a diversified portfolio of regulated utility systems throughout the United States serving approximately 756,000 customers. 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.

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, and Texas which together serve approximately 158,000 connections.

Corporate Development

The Company is presently developing a portfolio of projects that when constructed will add approximately 361 MW of generation capacity from wind and solar powered generating facilities that have a production-weighted average contract life of 22 years.

2017 Major Highlights

Corporate Highlights

Strong Operating Results

APUC recorded strong operating results for the three months of operations relative to the same period last year. The accretion of the Empire acquisition continues to be evident in the Liberty Utilities Group's profit and the Liberty Power Group has benefited from the addition of new generating stations and higher production from its U.S. wind facilities.

(all dollar amounts in \$ millions except per share information)	Three Months Ended June 30		
	2017	2016	Change
Net earnings attributable to shareholders	\$ 47.7	\$ 24.8	92%
Adjusted Net Earnings	\$ 53.3	\$ 30.9	72%
Adjusted EBITDA	\$ 197.6	\$ 99.2	99%
Net earnings per common share	\$ 0.12	\$ 0.08	50%
Adjusted Net Earnings per common share	\$ 0.13	\$ 0.11	18%

Declaration of Canadian Equivalent Third Quarter Dividend of Cdn \$0.1480 (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.

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

	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Total
U.S. dollar dividend	\$0.1059	\$0.1165	\$0.1165	\$0.1165	\$0.4554
Canadian dollar equivalent	\$0.1427	\$0.1533	\$0.1593	\$0.1480	\$0.6033

Liberty Utilities Group Highlights

Approval to acquire the Perris Water Distribution System

On August 10, the Company's board approved the acquisition of two water distribution systems serving approximately 4,095 customers from the City of Perris, California. The anticipated purchase price of U.S. \$11.5 million is expected to be established as rate base during the regulatory approval process. Liberty was the successful bidder in the city's request for proposal process and in July 2017 the Perris City council voted to approve the sale to Liberty. The public vote approving the sale is scheduled for November 2017. Once approved for sale by the residents of Perris, the transaction will be submitted to the California Public Utility Commission for approval in 2018.

Successful Rate Case Outcomes

A core strategy of the Liberty Utilities Group is to ensure an appropriate return is earned on the rate base at its various utility systems. During the three months ended June 30, 2017, the Liberty Utilities Group successfully completed six rate cases representing a cumulative annualized revenue increase of approximately U.S. \$14.0 million (see *Regulatory Proceedings*).

2017 Second Quarter Results From Operations

Key Financial Information

(all dollar amounts in \$ millions except per share information)	Three Months Ended June 30	
	2017	2016
Revenue	\$ 453.2	\$ 222.8
Net earnings attributable to shareholders	47.7	24.8
Cash provided by operating activities	133.4	89.9
Adjusted Net Earnings ¹	53.3	30.9
Adjusted EBITDA ¹	197.6	99.2
Adjusted Funds from Operations ¹	119.6	77.5
Dividends declared to common shareholders	61.4	37.1
Weighted average number of common shares outstanding	385,486,772	271,570,250
Per share		
Basic net earnings	\$ 0.12	\$ 0.08
Diluted net earnings	\$ 0.12	\$ 0.08
Adjusted Net Earnings ^{1,2}	\$ 0.13	\$ 0.11
Dividends declared to common shareholders	\$ 0.16	\$ 0.14

¹ Non-GAAP Financial Measures.

² APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.

For the three months ended June 30, 2017, APUC experienced an average U.S. exchange rate of approximately 1.3448 as compared to 1.2882 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 June 30, 2017, APUC reported total revenue of \$453.2 million as compared to \$222.8 million during the same period in 2016, an increase of \$230.4 million. The major factors resulting in the increase in APUC revenue in the three months ended June 30, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in \$ millions)

Three Months
Ended June 30

Comparative Prior Period Revenue	\$ 222.8
LIBERTY POWER GROUP	
Existing Facilities	
Hydro: Increase primarily due to higher production across all regions partially offset by lower average market rates in the Western and Maritime regions.	0.5
Wind Canada: Decrease primarily due to lower production at the St. Leon and St. Damase Wind Facilities.	(0.3)
Wind U.S.: Increase primarily due to higher production and market prices at all sites.	1.8
Solar Canada: Decrease due to a Hydro One grid outage in April, and lower irradiance during the second quarter resulting in lower production at the Cornwall Solar Facility.	(0.6)
Solar U.S.: Increase due to higher production at the Bakersfield I Solar Facility.	0.2
Thermal: Increase due to higher production and energy costs at the Windsor Locks Thermal Facility offset by a decline in pricing and production at the Sanger Thermal Facility.	0.3
Other:	(0.6)
	1.3
New Facilities	
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.	14.2
Solar U.S.: Bakersfield II Solar Facility was placed in service in December 2016.	0.7
	14.9
Foreign Exchange	1.5
LIBERTY UTILITIES GROUP	
Existing Facilities	
Electricity: Increase primarily due to higher pass through costs.	1.5
Gas: Increase primarily due to higher pass-through costs at the Midstates, Peach State, and New England Gas Systems.	4.1
Water: Decrease primarily due to completion of condemnation proceedings on June 22, 2017, and reduction in rates and volumes at the Mountain Water System in the prior year.	(0.7)
Other:	(0.1)
	4.8
New Facilities	
Electricity: Acquisition of both the Empire's electric distribution system (U.S. \$179.0 million) on January 1, 2017, and the Luning Solar Facility (U.S. \$3.4 million) on February 15, 2017.	183.0
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.	8.2
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.	1.9
	193.8
Rate Cases	
Electricity: Implementation of new rates at the CalPeco and Granite State Electric Systems.	4.3
Gas: Implementation of new rates at the New England and Peach State Gas Systems.	0.9
Water: Implementation of new rates at the Bella Vista, Park Water (Central Basin), and Rio Rico Water Systems.	1.7
	6.9
Foreign Exchange	7.2
Current Period Revenue	\$ 453.2

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

For the three months ended June 30, 2017, net earnings attributable to shareholders totaled \$47.7 million as compared to \$24.8 million during the same period in 2016, an increase of \$22.9 million or 93.1%. The increase was primarily due to a \$94.2 million increase in earnings from operating facilities (including Empire), \$1.1 million decrease in acquisition related costs, \$5.8 million increase in foreign exchange gain, \$0.5 million increase in interest, dividend equity and other income, \$0.6 million decrease in losses from derivative instruments, and \$10.0 million increase in losses attributable to non-controlling interests. These items were partially offset by a \$4.0 million decrease in gains on long lived assets, \$4.9 million decrease in other gains, \$6.3 million increase in administration charges, \$39.5 million increase in depreciation and amortization expenses, \$16.9 million increase in interest expense and \$17.7 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*).

During the three months ended June 30, 2017, cash provided by operating activities totaled \$133.4 million as compared to cash provided by operating activities of \$89.9 million during the same period in 2016. During the three months ended June 30, 2017, Adjusted Funds from Operations totaled \$119.6 million compared to Adjusted Funds from Operations of \$77.5 million during the same period in 2016. The change in Adjusted Funds from Operations in the three months ended June 30, 2017 is primarily due to increased earnings from operations (including Empire) as compared to the same period in 2016.

During the three months ended June 30, 2017 Adjusted EBITDA totaled \$197.6 million as compared to \$99.2 million during the same period in 2016, an increase of \$98.4 million or 99.2%. 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 Year-to-Date Results From Operations

Key Financial Information

	Six Months Ended June 30	
(all dollar amounts in \$ millions except per share information)	2017	2016
Revenue	\$ 1,011.1	\$ 564.5
Net earnings attributable to shareholders	73.7	66.8
Cash provided by operating activities	168.8	143.4
Adjusted Net Earnings ¹	141.4	87.2
Adjusted EBITDA ¹	452.6	247.2
Adjusted Funds from Operations ¹	328.5	199.4
Dividends declared to common shareholders	120.4	72.0
Weighted average number of common shares outstanding	364,634,149	270,068,016
Per share		
Basic net earnings	\$ 0.19	\$ 0.23
Diluted net earnings	\$ 0.19	\$ 0.23
Adjusted Net Earnings ^{1,2}	\$ 0.37	\$ 0.31
Dividends declared to common shareholders	\$ 0.31	\$ 0.26
	As at	
	June 30, 2017	December 31, 2016
Total assets	\$ 10,528.6	\$ 8,249.5
Long term debt ³	\$ 4,418.0	\$ 4,272.0

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 six months ended June 30, 2017, APUC experienced an average U.S. exchange rate of approximately 1.3339 as compared to 1.3312 in the same period in 2016. As such, any year-over-year 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 six months ended June 30, 2017, APUC reported total revenue of \$1,011.1 million as compared to \$564.5 million during the same period in 2016, an increase of \$446.6 million or 79.1%. The major factors resulting in the increase in APUC revenue for the six months ended June 30, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in \$ millions)

Six Months
Ended June 30

Comparative Prior Period Revenue	\$ 564.5
LIBERTY POWER GROUP	
Existing Facilities	
Hydro: Decrease primarily due to the global adjustment from the Ontario Energy Finance Corporation in 2016, as well as lower production in Maritime and Quebec regions.	(1.4)
Wind Canada: Increase primarily due to higher production and annual rate increases.	0.2
Wind U.S.: Increase primarily due to higher production at all sites, and market price increases at Minonk and Sandy Ridge Wind Facilities.	0.6
Solar Canada: Decrease due to a Hydro One grid outage in April, and lower irradiance during the second quarter resulting in lower production at the Cornwall Solar Facility.	(0.6)
Solar U.S.: Decrease due to business interruption insurance proceeds received in Q1 2016 in excess of current year operating profit for the Bakersfield I Solar Facility.	(0.3)
Thermal: Increase in production and energy costs resulted in higher revenue at the Windsor Locks Thermal Facility and was offset by a decline in pricing and production at the Sanger Thermal Facility.	1.1
Other: Decrease is primarily due to a new capacity-based contract at the Sanger Thermal Facility.	(1.2)
	(1.6)
New Facilities	
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.	22.8
Solar U.S.: Bakersfield II Solar Facility was placed in service in December 2016.	1.0
	23.8
Foreign Exchange	(0.2)
LIBERTY UTILITIES GROUP	
Existing Facilities	
Electricity: Decrease primarily due to lower pass through energy costs.	(6.4)
Gas: Increase primarily due to the higher pass through gas costs at the EnergyNorth, New England, and Peach State Gas Systems, partially offset by decreased pass-through costs at the Midstates Gas System and lower overall volumes.	18.9
Water: Increase primarily due to higher usage, partially offset by the completion of the condemnation proceedings on June 22, 2017, and reduction in rates and volumes at the Mountain Water System compared to the prior year.	0.1
Other:	0.8
	13.4
New Facilities	
Electricity: Increase is due to the acquisition of Empire's electric distribution system (U.S. \$354.4 million) on January 1, 2017, and the Luning Solar Facility (U.S. \$7.8 million) on February 15, 2017.	367.2
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.	26.4
Water: Acquisition of Empire's water distribution system on January 1, 2017.	1.3
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.	4.0
	398.9
Rate Cases	
Electricity: Implementation of new rates at the CalPeco and Granite State Electric Systems.	7.2
Gas: Implementation of new rates at the Midstates, New England, and Peach State Gas Systems.	6.8
Water: Implementation of new rates at the Bella Vista, Park Water (Central Basin), and Rio Rico Water Systems.	2.2
	16.2
Foreign Exchange	(3.9)
Current Period Revenue	\$ 1,011.1

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

For the six months ended June 30, 2017, net earnings attributable to shareholders totaled \$73.7 million as compared to \$66.8 million during the same period in 2016, an increase of \$6.9 million. The increase was due to a \$195.6 million increase in earnings from operating facilities, \$1.2 million increase in interest, dividend, equity and other income, \$0.1 million decrease on losses from derivative instruments, \$5.4 million increase in foreign exchange gains, \$2.2 million increase in gains on long lived assets, and \$18.6 million increase in losses attributable to non-controlling interests. These items were partially offset by a \$72.5 million increase in depreciation and amortization expenses, \$9.5 million increase in administration charges, \$6.1 million decrease in other gains, \$56.5 million increase in interest expense, \$18.6 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*), and \$53.0 million increase in acquisition costs as compared to the same period in 2016.

During the six months ended June 30, 2017, cash provided by operating activities totaled \$168.8 million as compared to cash provided by operating activities of \$143.4 million during the same period in 2016. During the six months ended June 30, 2017, Adjusted Funds from Operations, a non-GAAP measure, totaled \$328.5 million as compared to Adjusted Funds from Operations of \$199.4 million the same period in 2016, an increase of \$129.1 million.

Adjusted EBITDA in the six months ended June 30, 2017 totaled \$452.6 million as compared to \$247.2 million during the same period in 2016, an increase of \$205.4 million or 83.1%. A detailed analysis of this variance 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 June 30, 2017 totaled \$197.6 million as compared to \$99.2 million during the same period in 2016, an increase of \$98.4 million or 99.2%. Adjusted EBITDA in the six months ended June 30, 2017 totaled \$452.6 million as compared to \$247.2 million during the same period in 2016, an increase of \$205.4 million or 83.1%. The breakdown of Adjusted EBITDA by the company's main operating segments and a summary of changes are shown below.

Adjusted EBITDA by business units (all dollar amounts in \$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Liberty Power Group Operating Profit	\$ 66.9	\$ 47.0	\$ 136.9	\$ 110.5
Liberty Utilities Group Operating Profit	146.7	61.9	345.4	157.1
Administrative Expenses	(16.7)	(10.4)	(31.3)	(21.8)
Other Income & Expenses	0.7	0.7	1.6	1.4
Total Algonquin Power & Utilities Adjusted EBITDA	\$ 197.6	\$ 99.2	\$ 452.6	\$ 247.2
Change in Adjusted EBITDA (\$)	\$ 98.4		\$ 205.4	
Change in Adjusted EBITDA (%)	99.2%		83.1%	

Change in Adjusted EBITDA (all dollar amounts in \$ millions)	Three Months Ended June 30, 2017			
	Power	Utilities	Corporate	Total
Prior period balances	\$ 47.0	\$ 61.9	\$ (9.7)	\$ 99.2
Existing Facilities	4.6	(5.8)	—	(1.2)
New Facilities	13.9	81.0	—	94.9
Rate Cases	—	6.9	—	6.9
Foreign Exchange Impact	1.4	2.7	—	4.1
Administrative Expenses	—	—	(6.3)	(6.3)
Total change during the period	\$ 19.9	\$ 84.8	\$ (6.3)	\$ 98.4
Current period balances	\$ 66.9	\$ 146.7	\$ (16.0)	\$ 197.6

Change in Adjusted EBITDA

(all dollar amounts in \$ millions)

Six Months Ended June 30, 2017

	Power	Utilities	Corporate	Total
Prior period balances	\$ 110.5	\$ 157.1	\$ (20.4)	\$ 247.2
Existing Facilities	1.4	1.2	0.2	2.8
New Facilities	24.6	172.0	—	196.6
Rate Cases	—	16.2	—	16.2
Foreign Exchange Impact	0.4	(1.1)	—	(0.7)
Administration Expenses	—	—	(9.5)	(9.5)
Total change during the period	\$ 26.4	\$ 188.3	\$ (9.3)	\$ 205.4
Current period balances	\$ 136.9	\$ 345.4	\$ (29.7)	\$ 452.6

LIBERTY POWER GROUP

2017 Electricity Generation Performance

(Performance in GW-hrs sold)	Long Term Average Resource	Three Months Ended June 30		Long Term Average Resource	Six Months Ended June 30	
		2017	2016		2017	2016
Hydro Facilities:						
Maritime Region	62.4	48.1	46.5	89.9	82.5	94.2
Quebec Region	82.4	86.2	79.5	138.4	147.8	153.3
Ontario Region	37.2	35.8	31.5	75.5	70.8	71.8
Western Region	19.0	22.8	9.8	28.6	33.0	20.6
	201.0	192.9	167.3	332.4	334.1	339.9
Wind Facilities:						
St. Damase	16.4	14.8	16.1	37.3	35.8	38.6
St. Leon	99.5	107.9	113.8	220.9	221.0	204.8
Red Lily ¹	20.8	23.0	22.2	44.0	46.7	40.7
Morse	25.2	27.0	25.0	55.7	52.4	46.9
Sandy Ridge	37.7	39.7	31.1	84.8	90.5	80.2
Minonk	167.8	181.0	154.1	355.2	387.4	363.5
Senate	137.4	133.0	111.9	288.7	281.4	265.3
Shady Oaks	92.4	99.1	74.0	200.6	209.6	171.6
Odell ²	208.2	201.8	—	438.7	433.1	—
Deerfield ³	130.5	136.8	—	206.3	210.5	—
	935.9	964.1	548.2	1,932.2	1,968.4	1,211.6
Solar Facilities:						
Cornwall	5.1	4.4	5.8	7.7	6.9	8.3
Bakersfield I	17.8	16.5	14.7	26.9	25.2	22.6
Bakersfield II ⁴	8.5	7.8	—	12.3	11.7	—
	31.4	28.7	20.5	46.9	43.8	30.9
Renewable Energy Performance	1,168.3	1,185.7	736.0	2,311.5	2,346.3	1,582.4
Thermal Facilities:						
Windsor Locks	N/A ⁵	29.2	26.9	N/A ⁵	59.2	55.1
Sanger	N/A ⁵	19.3	25.9	N/A ⁵	34.4	57.9
		48.5	52.8		93.6	113.0
Total Performance		1,234.2	788.8		2,439.9	1,695.4

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 Second Quarter Liberty Power Group Performance

For the three months ended June 30, 2017, the Liberty Power Group generated 1,234.2 GW-hrs of electricity as compared to 788.8 GW-hrs during the same period of 2016.

For the three months ended June 30, 2017, the hydro facilities generated 192.9 GW-hrs of electricity as compared to 167.3 GW-hrs produced in the same period in 2016, an increase of 15.3%. Electricity generated represented 96.0% of long-term average resources ("LTAR") as compared to 83.2% during the same period in 2016. During the quarter, generation in the Quebec and Western regions surpassed their respective LTARs.

For the three months ended June 30, 2017, the wind facilities produced 964.1 GW-hrs of electricity as compared to 548.2 GW-hrs produced in the same period in 2016, an increase of 75.9%. The higher generation was primarily due to production at the Odell and Deerfield Wind Facilities, which achieved commercial operations ("COD") on July 29, 2016 and February 21, 2017, respectively. These items were partly offset by lower production at the St. Damase and St. Leon Wind Facilities. During the three months ended June 30, 2017, the wind facilities generated electricity equal to 103.0% of LTAR as compared to 92.1% during the same period in 2016. The change is primarily attributable to an increase in production across all U.S. Wind Facilities as well as incremental electricity generated at the Odell and Deerfield Wind Facilities.

For the three months ended June 30, 2017, the solar facilities generated 28.7 GW-hrs of electricity as compared to 20.5 GW-hrs of electricity in the same period in 2016, an increase of 40.0%. The increase in production is largely attributable to the new Bakersfield II Solar Facility. Excluding the new facility, Cornwall and Bakersfield I had a production increase of 2.0%.

For the three months ended June 30, 2017, the thermal facilities generated 48.5 GW-hrs of electricity as compared to 52.8 GW-hrs of electricity during the same period in 2016. During the same period, the Windsor Locks Thermal Facility generated 143.9 billion lbs of steam as compared to 133.6 billion lbs of steam during the same period in 2016.

2017 Year-to-Date Liberty Power Performance

For the six months ended June 30, 2017, the Liberty Power Group generated 2,439.9 GW-hrs of electricity as compared to 1,695.4 GW-hrs during the same period of 2016.

For the six months ended June 30, 2017, the hydro facilities generated 334.1 GW-hrs of electricity as compared to 339.9 GW-hrs produced in the same period in 2016, a decrease of 1.7%. Electricity generated represented 100.5% of long-term projected average resources as compared to 102.3% during the same period in 2016. During the six months ended June 30, 2017, the Quebec and Western regions achieved production above their LTAR, while production in the Maritime and Ontario regions was below their respective LTAR.

For the six months ended June 30, 2017, the wind facilities produced 1,968.4 GW-hrs of electricity as compared to 1,211.6 GW-hrs produced in the same period in 2016, an increase of 62.5%. During the six months ended June 30, 2017, the wind facilities generated electricity equal to 101.9% of LTAR as compared to 95.6% during the same period in 2016. The change is primarily attributable to an increase in production across all U.S. Wind Facilities as well as incremental electricity generated at the Odell and Deerfield Wind Facilities.

For the six months ended June 30, 2017, the solar facilities generated 43.8 GW-hrs of electricity as compared to 30.9 GW-hrs of electricity produced in the same period in 2016, an increase of 41.7%. The increase in production is primarily attributable to production at the new Bakersfield II Solar Facility which achieved COD on January 11, 2017. Excluding Bakersfield II, production from all solar facilities increased 3.9% as compared to the same period last year.

For the six months ended June 30, 2017, the thermal facilities generated 93.6 GW-hrs of electricity as compared to 113.0 GW-hrs of electricity during the same period in 2016. During the same period, the Windsor Locks Thermal Facility generated 310.4 billion lbs of steam as compared to 319.3 billion lbs of steam during the same period in 2016.

2017 Liberty Power Group Operating Results

(all dollar amounts in \$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Revenue ¹				
Hydro	\$ 15.1	\$ 14.2	\$ 32.6	\$ 34.0
Wind	44.8	27.4	88.9	63.0
Solar	4.6	4.2	6.7	6.6
Thermal	8.6	8.1	16.6	16.0
Total Revenue	\$ 73.1	\$ 53.9	\$ 144.8	\$ 119.6
Less:				
Cost of Sales - Energy ²	(0.9)	(1.2)	(2.7)	(2.3)
Cost of Sales - Thermal	(4.1)	(2.2)	(9.6)	(6.7)
Realized loss on hedges ³	—	—	(0.7)	(0.9)
Net Energy Sales	\$ 68.1	\$ 50.5	\$ 131.8	\$ 109.7
Renewable Energy Credits ("REC")	3.5	4.2	8.3	10.3
Other Revenue	0.1	0.9	0.3	1.4
Total Net Revenue	\$ 71.7	\$ 55.6	\$ 140.4	\$ 121.4
Expenses & Other Income				
Operating expenses	(23.0)	(18.5)	(42.2)	(34.8)
Interest, dividend, equity and other income	0.7	1.1	1.9	1.7
HLBV income ⁴	17.5	8.8	36.8	22.2
Divisional Operating Profit⁵	\$ 66.9	\$ 47.0	\$ 136.9	\$ 110.5

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 Unaudited Interim Consolidated 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 Second Quarter Operating Results

For the three months ended June 30, 2017, the Liberty Power Group generated \$66.9 million of operating profit as compared to \$47.0 million during the same period in 2016, which represents an increase of \$19.9 million, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in \$ millions)		Three Months Ended June 30
Prior Period Operating Profit	\$	47.0
Existing Facilities		
Hydro: An increase in production resulted in higher revenues which were partly offset by lower average market rates in the Western and Maritime regions.		0.2
Wind Canada: Decrease due to lower production at the St. Leon and St. Damase Wind Facilities.		(0.3)
Wind U.S.: Increase primarily due to higher production and market prices.		5.9
Solar Canada: Decrease primarily due to lower production.		(0.4)
Solar U.S.: Increase due to higher production at the Bakersfield I Solar Facility.		0.2
Thermal: Decrease primarily due to higher energy costs at the Windsor Locks Thermal Facility and lower production at the Sanger Thermal Facility.		(1.4)
Other:		0.4
		4.6
New Facilities		
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind facilities.		12.7
Solar U.S.: Bakersfield II was placed in service in December 2016.		1.2
		13.9
Foreign Exchange		1.4
Current Period Divisional Operating Profit	\$	66.9

2017 Year-to-Date Operating Results

For the six months ended June 30, 2017, the Liberty Power Group generated \$136.9 million of operating profit as compared to \$110.5 million during the same period in 2016, which represents an increase of \$26.4 million or 23.9%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in \$ millions)		Six Months Ended June 30
Prior Period Operating Profit	\$	110.5
Existing Facilities		
Hydro: Decrease primarily due to the Global Adjustment from OEFC in Ontario in 2016 as well as a decrease in production in Maritime and Quebec regions.		(2.9)
Wind Canada: Increase is primarily due to an increase in production and annual rate increases.		0.1
Wind U.S.: Increase is primarily due to higher production and increased HLBV income.		6.5
Solar Canada: Decrease primarily due to lower production.		(0.3)
Solar U.S.: Decrease is primarily due to business interruption insurance proceeds received in Q1 2016 in excess of current year operating profit.		(0.3)
Thermal: Decrease primarily due to higher energy costs at the Windsor Locks Thermal Facility and lower production at the Sanger Thermal Facility.		(1.8)
Other:		0.1
		1.4
New Facilities		
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind facilities.		23.1
Solar U.S.: Bakersfield II (December 2016).		1.5
		24.6
Foreign Exchange		0.4
Current Period Divisional Operating Profit	\$	136.9

LIBERTY UTILITIES GROUP

The Liberty Utilities Group operates rate-regulated utilities that provide distribution services to approximately 756,000 connections in the natural gas, electric, water and wastewater sectors. On January 1, 2017, Liberty Utilities completed the acquisition of The Empire District Electric Company ("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 June 30			
	2017		2016	
(all dollar amounts in U.S. \$ millions)	Assets	Total Connections ¹	Assets	Total Connections ¹
Electricity	\$ 2,476.8	263,000	\$ 351.7	93,000
Natural Gas	939.1	335,000	794.8	293,000
Water and Wastewater	490.7	158,000	502.6	178,000
Total	\$ 3,906.6	756,000	\$ 1,649.1	564,000
Accumulated Deferred Income Taxes Liability	\$ 665.5		\$ 166.5	

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 158,000 connections located in the states of Arkansas, Arizona, California, Illinois, Missouri, and Texas.

2017 Second Quarter Usage Results

Electric Distribution Systems

	Three Months Ended June 30	
	2017	2016
Average Active Electric Connections For The Period		
Residential	223,300	80,200
Commercial and industrial	39,100	12,400
Total Average Active Electric Connections For The Period	262,400	92,600
Customer Usage (GW-hrs)		
Residential	488.6	121.8
Commercial and industrial	868.6	215.4
Total Customer Usage (GW-hrs)	1,357.2	337.2

For the three months ended June 30, 2017 the electric distribution systems' usage totaled 1,357.2 GW-hrs as compared to 337.2 GW-hrs for the same period in 2016, an increase of 1,020.0 GW-hrs or 302.5%. The addition of Empire accounted for 1,014.1 GW-hrs of the increase. The CalPeco Electric System and Granite State Electric System usage totaled 343.1 GW-hrs, an increase of 5.9 GW-hrs or 1.7%.

Natural Gas Distribution Systems

	Three Months Ended June 30	
	2017	2016
Average Active Natural Gas Connections For The Period		
Residential	287,300	249,700
Commercial and industrial	31,600	26,400
Total Average Active Natural Gas Connections For The Period	318,900	276,100
Customer Usage (MMBTU)		
Residential	2,877,000	2,776,000
Commercial and industrial	2,067,000	1,803,000
Total Customer Usage (MMBTU)	4,944,000	4,579,000

For the three months ended June 30, 2017, usage at the natural gas distribution systems totaled 4,944,000 MMBTU as compared to 4,579,000 MMBTU during the same period in 2016, an increase of 365,000 MMBTU, or 8.0%. The addition of Empire accounted for 366,000 MMBTU of the increase.

Water and Wastewater Distribution Systems

	Three Months Ended June 30	
	2017	2016
Average Active Connections For The Period		
Wastewater connections	41,000	40,400
Water distribution connections	127,200	131,200
Total Average Active Connections For The Period	168,200	171,600
Gallons Provided		
Wastewater treated (millions of gallons)	535	562
Water sold (millions of gallons)	4,732	4,654
Total Gallons Provided	5,267	5,216

During the three months ended June 30, 2017, the water and wastewater distribution systems provided approximately 4,732 million gallons of water to its customers and treated approximately 535 million gallons of wastewater as compared to 4,654 million gallons of water provided and 562 million gallons of wastewater treated during the same period in 2016. The addition of Empire accounted for most of the increase. Usage at the Mountain Water System was 670 million gallons during three months ended June 30, 2017.

2017 Second Quarter Operating Results

	Three Months Ended June 30			
	2017 U.S. \$ (millions)	2016 U.S. \$ (millions)	2017 Cdn \$ (millions)	2016 Cdn \$ (millions)
Revenue				
Utility electricity sales and distribution	\$ 177.7	\$ 37.2	\$ 238.7	\$ 47.9
Less: cost of sales – electricity	(51.0)	(19.2)	(68.4)	(24.7)
Net Utility Sales - electricity	126.7	18.0	170.3	23.2
Utility natural gas sales and distribution	56.4	48.3	76.0	62.2
Less: cost of sales – natural gas	(16.4)	(11.5)	(22.1)	(14.8)
Net Utility Sales - natural gas	40.0	36.8	53.9	47.4
Utility water distribution & wastewater treatment sales and distribution	37.9	36.6	50.9	47.1
Less: cost of sales – water	(2.4)	(2.3)	(3.2)	(3.0)
Net Utility Sales - water distribution & wastewater treatment	35.5	34.3	47.7	44.1
Gas transportation	6.3	4.7	8.5	6.1
Other revenue	1.8	0.4	2.4	0.5
Net Utility Sales	\$ 210.3	\$ 94.2	\$ 282.8	\$ 121.3
Operating expenses	(103.6)	(46.9)	(139.4)	(60.8)
Other income	0.9	1.1	1.2	1.4
HLBV	1.6	—	2.1	—
Divisional Operating Profit¹	\$ 109.2	\$ 48.4	\$ 146.7	\$ 61.9

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

For the three months ended June 30, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. \$109.2 million as compared to U.S. \$48.4 million for the comparable period in the prior year. Measured in Canadian dollars, the group's operating profit was \$146.7 million as compared to \$61.9 million during the same period in 2016, which represents an increase of \$84.8 million or 137%, excluding corporate administration expenses. The operating profit for the three months ended June 30, 2017, attributable to the Mountain Water System was U.S. \$1.1 million.

Highlights of the changes are summarized in the following table:

(all dollar amounts in \$ millions)		Three Months Ended June 30
Prior Period Operating Profit	\$	61.9
Existing Facilities		
Electricity: Decrease primarily due to higher operating expenses at the CalPeco Electric System partially offset by higher net utility sales margin at the Granite State Electric System.		(0.9)
Gas: Decrease primarily due to higher operating costs at the EnergyNorth and Keene Gas systems.		(2.1)
Water: Decrease primarily due to a reduction in rates and volumes at the Mountain Water System, coupled with higher operating costs at the water utilities. In addition, there was a reduction in demand in the Central region due to excessive rain in June.		(2.2)
Other:		(0.6)
		(5.8)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system on January 1, 2017(U.S. \$72.9), and the Luning Solar Facility on February 15, 2017 (U.S. \$5.3).		78.2
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		1.4
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.4
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		1.0
		81.0
Rate Cases		
Electricity: Implementation of new rates at the CalPeco and Granite State Electric Systems.		4.3
Gas: Implementation of new rates at the New England and Peach State Gas Systems.		0.9
Water: Implementation of new rates at the Bella Vista, Park Water (Central Basin), and Rio Rico Water Systems.		1.7
		6.9
Foreign Exchange		2.7
Current Period Divisional Operating Profit	\$	146.7

2017 Year-to-Date Usage Results

Electric Distribution Systems

	Six Months Ended June 30	
	2017	2016
Average Active Electric Connections For The Period		
Residential	223,400	80,300
Commercial and industrial	39,100	12,500
Total Average Active Electric Connections For The Period	262,500	92,800
Customer Usage (GW-hrs)		
Residential	1,131.9	287.6
Commercial and industrial	1,687.1	434.9
Total Customer Usage (GW-hrs)	2,819.0	722.5

For the six months ended June 30, 2017 the electric distribution systems' usage totaled 2,819.0 GW-hrs as compared to 722.5 GW-hrs for the same period in 2016, an increase of 2,096.5 GW-hrs. The addition of Empire accounted for 2,085.9 GW-hrs of the increase. Customer usage at the CalPeco Electric System was 13.6 GW-hrs higher and was partially offset by 3.1 GW-hrs of lower usage at the Granite State Electric System due to warmer weather experienced in the region.

Natural Gas Distribution Systems

	Six Months Ended June 30	
	2017	2016
Average Active Natural Gas Connections For The Period		
Residential	289,400	251,100
Commercial and industrial	32,000	26,900
Total Average Active Natural Gas Connections For The Period	321,400	278,000
Customer Usage (MMBTU)		
Residential	11,322,000	10,647,000
Commercial and industrial	6,909,000	6,639,000
Total Customer Usage (MMBTU)	18,231,000	17,286,000

For the six months ended June 30, 2017, usage at the natural gas distribution systems totaled 18,231,000 MMBTU as compared to 17,286,000 MMBTU during the same period in 2016, an increase of 945,000 MMBTU or 5.5%. The addition of Empire accounted for 1,756,000 MMBTU of the increase. The Midstates and New England Gas Systems experienced a lower number of heating degrees days which was partially offset by higher demand at the EnergyNorth Gas System.

Water and Wastewater Distribution Systems

	Six Months Ended June 30	
	2017	2016
Average Active Connections For The Period		
Wastewater connections	41,000	43,100
Water distribution connections	131,100	133,900
Total Average Active Connections For The Period	172,100	177,000
Gallons Provided		
Wastewater treated (millions of gallons)	1,124	1,160
Water sold (millions of gallons)	8,102	7,721
Total Gallons Provided	9,226	8,881

During the six months ended June 30, 2017, the water and wastewater distribution systems provided approximately 8,102 million gallons of water to its customers and treated approximately 1,124 million gallons of wastewater as compared to 7,721 million gallons of water and 1,160 million gallons of wastewater during the same period in 2016. The addition of Empire

accounted for 153 million gallons of the increase in the water total. Usage at the Mountain Water System was 1,083 million gallons during six months ended June 30, 2017.

2017 Year-to-Date Operating Results

	Six Months Ended June 30			
	2017 U.S. \$ (millions)	2016 U.S. \$ (millions)	2017 Can \$ (millions)	2016 Can \$ (millions)
Revenue				
Utility electricity sales and distribution	\$ 359.1	\$ 83.2	\$ 478.8	\$ 111.3
Less: cost of sales – electricity	(105.6)	(47.6)	(140.7)	(63.9)
Net Utility Sales - electricity	253.5	35.6	338.1	47.4
Utility natural gas sales and distribution	193.4	157.8	257.2	213.3
Less: cost of sales – natural gas	(78.0)	(58.1)	(103.5)	(79.6)
Net Utility Sales - natural gas	115.4	99.7	153.7	133.7
Utility water distribution & wastewater treatment sales and distribution	70.3	66.7	93.8	88.5
Less: cost of sales – water	(4.4)	(4.3)	(5.9)	(5.7)
Net Utility Sales - water distribution & wastewater treatment	65.9	62.4	87.9	82.8
Gas transportation	17.3	13.7	23.0	19.0
Other revenue	3.7	1.1	5.0	1.1
Net Utility Sales	\$ 455.8	\$ 212.5	\$ 607.7	\$ 284.0
Operating expenses	(201.4)	(97.2)	(269.1)	(129.6)
Other income	1.9	2.0	2.5	2.7
HLBV	3.2	—	4.3	—
Divisional Operating Profit¹	\$ 259.5	\$ 117.3	\$ 345.4	\$ 157.1

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

For the six months ended June 30, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. \$259.5 million as compared to U.S. \$117.3 million for the comparable period in the prior year. Measured in Canadian dollars, the group's operating profit was \$345.4 million as compared to \$157.1 million during the same period in 2016, which represents an increase of \$188.3 million or 120%, excluding corporate administration expenses. The operating profit for the six months ended June 30, 2017, attributable to the Mountain Water System was U.S. \$1.9 million.

Highlights of the changes are summarized in the following table:

(all dollar amounts in \$ millions)		Six Months Ended June 30
Prior Period Operating Profit	\$	157.1
Existing Facilities		
Electricity: Increase primarily due to higher net utility sales margin at the Granite State Electric System, partially offset by higher operating expenses at the CalPeco Electric System.		0.8
Gas: Increase is primarily related to higher margin due to increased consumption at the EnergyNorth Gas System, partially offset by a lower number of heating degree days at the other gas systems.		2.0
Water: Decrease primarily due to higher operating costs at the Litchfield Park and Bella Vista Water Systems, and lower operating profit due to the disposition of the Mountain Water System on June 22, 2017.		(1.6)
Other:		—
		1.2
New Facilities		
Electricity: Increase is due to the acquisition of Empire's electric distribution system on January 1, 2017 (U.S. \$151.6), and the Luning Solar Facility on February 15, 2017 (U.S. \$11.2).		162.8
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		6.4
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.6
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		2.2
		172.0
Rate Cases		
Electricity: Implementation of new rates at the CalPeco and Granite State Electric Systems.		7.2
Gas: Implementation of new rates at the Midstates, New England, and Peach State Gas Systems.		6.8
Water: Implementation of new rates at the Bella Vista, Park Water (Central Basin), and Rio Rico Water Systems.		2.2
		16.2
Foreign Exchange		(1.1)
Current Period Divisional Operating Profit	\$	345.4

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 revenue increases of approximately U.S. \$0.3 million and U.S. \$0.25 million effective May 1, 2018 and May 1, 2019, respectively that relate to capital expenditures.
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.
Illinois Gas System	Illinois	General Rate Case	\$3.0	Final Order issued in May 2017 approving a U.S. \$2.2 million rate increase effective June 7, 2017.
Kansas Asbury Environmental and Riverton Cost Recovery ("AERR") Rider	Kansas	Rate Rider Recovery	\$1.1	Final Order issued in June 2017 approving a U.S. \$0.9 million revenue increase effective July 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 June 18, 2017.
New England Gas	Massachusetts	Decoupling Filing	\$0.2	Final Order issued in April 2017 approving a U.S. \$0.2 million revenue increase. New rates effective May 1, 2017.
Pending Rate Cases				
EnergyNorth Gas System	New Hampshire	General Rate Case	\$19.9	On April 28, 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 May 2018. Temporary rates of U.S. \$7.8 million were requested to be effective as of July 1, 2017. On June 30, 2017, the Commission approved temporary rates of U.S. \$6.8 million (87% of the requested amount) effective July 1, 2017 to be in place until the end of the Company's permanent rate case.
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 in rate base. On June 30, 2017, Liberty Utilities and ORA filed a joint motion to the Commission requesting approval of their filed settlement agreement. The settlement seeks recovery of costs via a Tier 2 advice letter to add the costs to rate base once the project reaches mechanical completion. The project is estimated to reach mechanical completion in mid-2018 and go into service in August 2018.
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). Final Order expected Q3 2017.
Woodmark/Tall Timbers Wastewater Systems	Texas	General Rate Case	\$1.6	On September 6, 2016, filed an application seeking a U.S. \$2.0 million revenue increase. On June 30, 2017, Liberty Utilities filed its rebuttal testimony, which revised its request to U.S. \$1.6 million. In July 2017, a settlement agreement in principle was reached among all parties, which is expected to be filed with the Commission in August, 2017. The settlement is subject to approval of the City of Tyler's council and the Commission. The parties have requested interim rates be effective as of August 1, 2017, with a final decision expected in Q4 2017/Q1 2018.

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 is being collected as of 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.

On October 31, 2016, the New England Natural Gas System filed its Gas System Enhancement Plan (GSEP) application seeking an 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.

On July 25, 2016, the Midstates Gas System filed a rate application with the Illinois Commerce Commission seeking a U.S. \$3.0 million annual revenue increase in natural gas rates. A hearing on the unanimous filed settlement was held on March 8, 2017 which set out an annual revenue increase of U.S. \$2.2 million, established a decoupling mechanism, a bad debt tracking mechanism, and a mechanism to enable further system expansion. The settlement is predicated on 49.5/50.5 capital structure and a 9.4% ROE. On May 24, 2017 the Commission issued an Order approving the settlement agreement with new tariff sheets being effective June 7, 2017.

On January 6, 2017, Empire Electric filed applications with the Kansas Corporate Commission for the Asbury Environmental and Riverton Cost Recovery ("AERR") Rider, requesting an incremental revenue increase of U.S. \$1.1 million due to inclusion of the Riverton 12 capital investment and continued collection of U.S. \$0.8 million from the Asbury capital investment. This Rider was authorized as part of the merger application settlement. An Order was issued June 29, 2017 approving a revenue increase of U.S. \$0.9 million. The revised Rider was implemented in July 1, 2017.

On July 25, 2016, Liberty Utilities Midstates filed a rate application with the Iowa Utilities Board seeking a U.S. \$1.06 million (46%) revenue increase in natural gas rates. On April 28, 2017 an Order was issued approving the settlement which set out an increase in annual revenues of U.S. \$1.0 million (93% of the requested increase), a 50/50 capital structure and 9.5% ROE. Rates are effective June 18, 2017.

Completion of Mountain Water Condemnation Proceedings

On May 6, 2014, the City of Missoula, Montana filed a lawsuit against Mountain Water Company and its prior indirect owner Carlyle Infrastructure Partners, L.P. ("Carlyle"), seeking to condemn the assets of Mountain Water. The case went to trial on the right to take or "necessity" phase in March, 2015. The District Court issued a Preliminary Order of Condemnation on June 15, 2015, finding that the City had established the right to take the assets of Mountain Water. Mountain Water filed an appeal with the Montana Supreme Court. The case then proceeded to a trial on valuation before three Commissioners. On November 17, 2015, the Commissioners issued a report finding that the "fair market value" of the condemned property as of May 6, 2014 was U.S. \$88.6 million. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision, permitting the City of Missoula to proceed with the condemnation of Mountain Water's assets.

On December 22, 2015, certain developers filed a lawsuit in Montana District Court against the City of Missoula and Mountain Water seeking resolution of claims to a portion of the condemnation award on the basis that certain of the assets being condemned had been funded by such parties. On February 21, 2017, the court in that case recognized an equitable lien on such assets in favor of the developers and ordered that a portion of the condemnation award, if and when paid, be paid by the City of Missoula to the court for direct payment to the developers.

On or about June 5, 2017, Mountain Water, Liberty Utilities Co. and the City of Missoula entered into a Settlement Agreement and Release of Claims, resolving certain issues in the event that the City acquired possession of Mountain Water's assets, and contingent upon settlement of the developer lawsuit. The settlement agreement was approved by the condemnation court in hearings on June 15 and June 22, 2017, and a final order of condemnation was issued on June 22, 2017. The developer lawsuit was dismissed on June 30, 2017. On June 22, 2017, the City of Missoula paid the condemnation judgment, including amounts owed to Mountain Water and amounts required to be paid to the developers. The City of Missoula took possession of Mountain Water's assets on that date. Carlyle and Mountain Water have the right to appeal issuance of the final order of condemnation.

In connection with Liberty Utilities' indirect acquisition of Mountain Water in January 2016, Liberty Utilities was permitted to hold-back U.S. \$14.4 million from the purchase price otherwise payable to Carlyle and certain other interest holders, pending resolution of amounts paid to Mountain Water and its affiliates in connection with the taking of Mountain Water's assets. Liberty Utilities and Carlyle have been unable to agree upon the disposition of that holdback amount. On or about June 30, 2017, Carlyle filed an action in the Court of Chancery in Delaware against Liberty Utilities, its subsidiary Western Water Holdings, LLC, and the Company seeking payment of a portion of that holdback amount. The suit has not yet been served on Liberty Utilities or the other defendants.

Park Water's debt indenture permits condemnation proceeds to be used to prepay, without penalty, debt issued under the indenture. As a result, on June 28, 2017, Park Water repaid U.S. \$63.0 million of debt with an average rate of approximately 6.5%.

CORPORATE DEVELOPMENT ACTIVITIES

The Company's Corporate Development group is focused on developing, contracting, and transitioning recently completed projects to the operations group. The group 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 Range (millions) ¹	Commercial Operation	PPA Term (Years)	Production (GW-hrs)
Projects in Construction						
Amherst Island Wind Project	Ontario	75	\$ 290 - \$ 325	2018	20	235
Great Bay Solar Project ²	Maryland	75	175 - 195	2017	10	146
Total Projects in Construction		150	\$ 465 - \$ 520			381
Projects in Development						
Blue Hill Wind Project	Saskatchewan	177	\$ 315 - \$ 350	2019/20	25	813
Val-Eo Wind Project ³	Quebec	24	60 - 70	2018	20	66
Turquoise Solar Project ⁴	Nevada	10	26 - 32	2018		28
Total Projects in Development		211	\$ 401 - \$ 452			907
Total in Construction and Development		361	\$ 866 - \$ 972			1,288

¹ 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.

² The total cost of the project is expected to be approximately \$135 - \$150 million in U.S. dollars.

³ All figures refer solely to Phase I of the Val-Eo Wind Project.

⁴ The Turquoise Solar Project will be included in the Rate Base of the CalPeco Electric System (see Regulatory Proceedings). The total cost of the project is expected to be approximately \$20 - \$25 million in U.S. dollars.

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. 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.

The total costs to complete the project are estimated at approximately \$290 million to \$325 million. Construction over the spring and summer months has focused primarily on the project's mainland interconnection switchyard and mainland dock, which are both underway. Manufacturing of major equipment (turbines, main power transformer) continues on schedule. Major construction activities will resume on the island late in the third quarter as planned, with turbine deliveries targeted to arrive on the island during the fourth quarter. Subject to receipt of ongoing construction-related permitting and negotiation of remaining agreements, construction is expected to be substantially completed 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 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 overall project construction is 80% complete. Piling work has been completed, racking and module installation is in progress. Installation of the project's inverters and transformers is also underway. Construction of the project substation is nearing completion, and work on the collection system and interconnection is progressing. Commercial operations is expected by the end of 2017.

The total costs to complete the project are estimated at approximately U.S. \$135 million to U.S. \$150 million. The Liberty Power Group expects the project will qualify for U.S. federal investment tax credits and accordingly, a tax equity investor has been selected to provide approximately 40% of the permanent project financing in return for the majority of the tax attributes.

Projects in Development

Turquoise Solar Project

The Turquoise Solar project is a 10.0 MW solar powered electric generating development project located in Washoe County in Nevada. The facility is comprised of 108,000 solar thin film panels and is being constructed on 110 acres of land. The Turquoise Solar Project is expected to generate 28 GW-hrs of energy per year and to be included in the rate base of the CalPeco Electric System (see *Regulatory Proceedings*). Mechanical completion is expected in mid-2018.

The total costs to complete the project are estimated at approximately U.S. \$20 million to U.S. \$25 million. The Liberty Utilities Group expects the project will qualify for U.S. federal investment tax credits and accordingly, approximately 30% of the permanent financing is expected to be funded by tax equity investors.

APUC: CORPORATE AND OTHER EXPENSES

(all dollar amounts in \$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Corporate and other expenses:				
Administrative expenses	\$ 16.7	\$ 10.4	\$ 31.3	\$ 21.8
Loss (gain) on foreign exchange	(3.9)	1.9	(3.8)	1.6
Interest expense on convertible debentures and acquisition facility due to the acquisition of Empire	—	16.5	17.6	22.4
Interest expense	50.0	16.5	97.0	35.7
Interest, dividend, equity, and other income ¹	(0.9)	(0.7)	(1.7)	(1.6)
Other gains ²	(4.9)	(13.8)	(4.9)	(8.8)
Acquisition-related costs	0.1	1.2	60.5	7.5
Loss on derivative financial instruments	—	0.6	1.4	1.5
Income tax expense	23.0	5.3	42.4	23.8

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 Second Quarter Corporate and Other Expenses

During the three months ended June 30, 2017, administrative expenses totaled \$16.7 million as compared to \$10.4 million in the same period in 2016. The \$6.3 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth, including ongoing administration expenses related to Empire.

For the three months ended June 30, 2017, interest expense totaled \$50.0 million as compared to \$16.5 million in the same period in 2016. The increase is primarily attributable to assumed and incremental debt related to the Empire acquisition debt, and new debt raised at Liberty Power and Liberty Utilities. (See *Credit Facilities & Debt and Unaudited Interim Consolidated Financial Statements note 7*.)

For the three months ended June 30, 2017, other gains were \$4.9 million as compared to gains of \$13.8 million in the same period in 2016. The current period gain is primarily related to the conclusion of the Mountain Water condemnation (see

Unaudited Interim Consolidated Financial Statements note 19). The prior period gain was primarily due to recognition of deferred income on completed facilities repairs where insurance proceeds were received in advance, and settlement of litigation and bankruptcy proceedings relating to Trafalgar Power Inc.

For the three months ended June 30, 2017, acquisition-related costs totaled \$0.1 million as compared to \$1.2 million in the same period in 2016. The decrease was primarily driven by Empire related acquisition costs recorded in 2016.

For the three months ended June 30, 2017, loss on derivative financial instruments totaled \$nil as compared to \$0.6 million in the same period in 2016.

For the three months ended June 30, 2017, income tax expense of \$23.0 million was recorded as compared to income tax expense of \$5.3 million during the same period in 2016. The increase in income tax expense is primarily due to the acquisition of Empire and the tax consequences of basis differences associated with the Mountain Water condemnation.

2017 Year-to-Date Corporate and Other Expenses

During the six months ended June 30, 2017, administrative expenses totaled \$31.3 million as compared to \$21.8 million in the same period in 2016. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth, including ongoing administration expenses related to Empire.

For the six months ended June 30, 2017, interest expense on convertible debentures and bridge financing totaled \$17.6 million (see *Convertible Unsecured Subordinated Debentures and Unaudited Interim Consolidated Financial Statements note 14*).

For the six months ended June 30, 2017, interest expense totaled \$97.0 million as compared to \$35.7 million in the same period in 2016. The increase in interest expense for the period is primarily attributable to assumed and incremental Empire Acquisition debt, and new debt raised at Liberty Power and Liberty Utilities. (See *Credit Facilities & Debt and Unaudited Interim Consolidated Financial Statements note 7*.)

For the six months ended June 30, 2017, other gains totaled a gain of \$4.9 million as compared to a gain of \$8.8 million in the same period in 2016. The current period gain is primarily related to the conclusion of the Mountain Water condemnation (see *Unaudited Interim Consolidated Financial Statements note 19*). The prior period gains primarily resulted from: (i) the recognition of deferred income on repairs completed for facilities where the insurance proceeds have been received in advance; and (ii) the settlement of litigation and bankruptcy proceedings relating to Trafalgar Power Inc. (see *Unaudited Interim Consolidated Financial Statements note 14*), partially offset by (iii) the write-down of the Company's equity interest in the natural gas development projects which have been cancelled by the developer.

For the six months ended June 30, 2017, acquisition related costs totaled \$60.5 million as compared to \$7.5 million in the same period in 2016. The increase is primarily attributable to the Empire acquisition. Acquisition related costs will vary from period to period depending on the level of activity and complexity associated with various acquisitions.

For the six months ended June 30, 2017, the gain on derivative financial instruments totaled \$1.4 million as compared to a gain of \$1.5 million in the same period in 2016.

An income tax expense of \$42.4 million was recorded in the six months ended June 30, 2017 as compared to an income tax expense of \$23.8 million during the same period in 2016. The increase in income tax expense for the six months ended June 30, 2017 is primarily related to the acquisition of Empire and the tax effect related to the Mountain Water condemnation.

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 June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Net earnings attributable to shareholders	\$ 47.7	\$ 24.8	\$ 73.7	\$ 66.8
Add (deduct):				
Net earnings attributable to the non-controlling interest, exclusive of HLBV	0.7	1.4	1.8	3.1
Income tax expense	23.0	5.3	42.4	23.8
Interest expense on convertible debentures and acquisition financing	—	16.5	17.6	22.4
Interest expense on long-term debt and others	50.0	16.5	97.0	35.7
Other gains	(0.1)	(5.0)	(0.1)	(6.2)
Gain on long-lived assets, net	(4.8)	(8.8)	(4.8)	(2.6)
Acquisition-related costs	0.1	1.2	60.5	7.5
Costs related to tax equity financing	0.6	—	0.6	—
Loss on derivative financial instruments	—	0.6	1.4	1.5
Realized gain on energy derivative contracts	—	—	(0.7)	(0.9)
Loss (gain) on foreign exchange	(3.9)	1.9	(3.8)	1.6
Depreciation and amortization	84.3	44.8	167.0	94.5
Adjusted EBITDA	\$ 197.6	\$ 99.2	\$ 452.6	\$ 247.2

HLBV represents the value of net tax attributes earned during the period from electricity generated by certain U.S. wind power and U.S. solar generation facilities. HLBV earned in the three and six months ended June 30, 2017 amounted to \$19.6 million and \$41.1 million, respectively.

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 June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Net earnings attributable to shareholders	\$ 47.7	\$ 24.8	\$ 73.7	\$ 66.8
Add (deduct):				
Loss on derivative financial instruments	—	0.6	1.4	1.5
Realized gain on derivative financial instruments	—	—	(0.7)	(0.9)
Gain on long-lived assets, net	(4.8)	(8.8)	(4.8)	(2.6)
Loss (gain) on foreign exchange	(3.9)	1.9	(3.8)	1.6
Interest expense on convertible debentures and acquisition financing	—	16.5	17.6	22.4
Acquisition-related costs	0.1	1.2	60.5	7.5
Costs related to tax equity financing	0.6	—	0.6	—
Adjustment for taxes related to above	13.6	(5.4)	(3.1)	(9.1)
Adjusted Net Earnings	\$ 53.3	\$ 30.9	\$ 141.4	\$ 87.2
Adjusted Net Earnings per share ¹	\$ 0.13	\$ 0.11	\$ 0.37	\$ 0.31

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 June 30, 2017, Adjusted Net Earnings totaled \$53.3 million as compared to \$30.9 million, an increase of \$22.4 million, as compared to the same period in 2016. The increase in Adjusted Net Earnings for the three months ended June 30, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and interest expense as compared to 2016.

For the six months ended June 30, 2017, Adjusted Net Earnings totaled \$141.4 million as compared to \$87.2 million, an increase of \$54.2 million, as compared to the same period in 2016. The increase in Adjusted Net Earnings for the six months ended June 30, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and interest 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 June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Cash flows from operating activities	\$ 133.4	\$ 89.9	\$ 168.8	\$ 143.4
Add (deduct):				
Changes in non-cash operating items	(15.4)	(22.5)	79.3	24.2
Production based cash contributions from non-controlling interests	1.5	1.0	10.6	10.5
Interest expense on convertible debentures and acquisition financing fees ¹	—	16.5	9.3	22.4
Acquisition-related costs	0.1	1.2	60.5	7.5
Cash generated from sale of long-lived assets	—	(8.6)		(8.6)
Adjusted Funds from Operations	\$ 119.6	\$ 77.5	\$ 328.5	\$ 199.4

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

For the six months ended June 30, 2017, Adjusted Funds from Operations totaled \$328.5 million as compared to Adjusted Funds from Operations of \$199.4 million, an increase of \$129.1 million as compared to the same period in 2016.

SUMMARY OF CAPITAL EXPENDITURES¹

(all dollar amounts in \$ millions)	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Liberty Power Group:				
Maintenance	\$ 2.5	\$ 9.9	\$ 10.3	\$ 21.4
Investment in Growth Capital Projects ¹	50.9	31.6	491.2	48.4
	\$ 53.4	\$ 41.5	\$ 501.5	\$ 69.8
Liberty Utilities Group:				
Rate Base Maintenance	\$ 56.3	\$ 23.9	\$ 112.8	\$ 52.2
Rate Base Acquisition	—	—	2,739.5	345.3
Rate Base Growth	62.1	22.3	194.8	26.3
	118.4	46.2	\$ 3,047.1	\$ 423.8
Total Capital Expenditures	\$ 171.8	\$ 87.7	\$ 3,548.6	\$ 493.6

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

2017 Second Quarter Capital Expenditures

During the three months ended June 30, 2017, the Liberty Power Group incurred capital expenditures of \$53.4 million as compared to \$41.5 million during the same period in 2016. The increase in capital expenditures is primarily due to the construction of the Great Bay Solar and Tinker Transmission Projects, and ongoing maintenance at operating sites.

During the three months ended June 30, 2017, the Liberty Utilities Group incurred capital expenditures of \$118.4 million as compared to \$46.2 million during the same period in 2016. The increase in capital expenditures is primarily due 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 Year-to-Date Capital Expenditures

During the six months ended June 30, 2017, the Liberty Power Group incurred capital expenditures of \$501.5 million as compared to \$69.8 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 and the Tinker Transmission Upgrade Projects, and ongoing maintenance at operating sites.

During the six months ended June 30, 2017, the Liberty Utilities Group incurred \$3.0 billion in capital expenditures as compared to \$423.8 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. \$2.4 billion), 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 are primarily due 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
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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 June 30, 2017:

	As at June 30, 2017				As at Dec 31, 2016
(all dollar amounts in \$ millions)	Corporate	Liberty Power	Liberty Utilities	Total	Total
Committed facilities	\$ 65.0	\$ 588.9	\$ 519.1	\$ 1,173.0	\$ 773.8
Funds drawn on facilities	—	(425.9)	(3.9)	(429.8)	(242.9)
Letters of credit issued	(11.7)	(75.1)	(42.5)	(129.3)	(234.9)
Liquidity available under the facilities	53.3	87.9	472.7	613.9	296.0
Cash on hand				31.9	110.4
Total Liquidity and Capital Reserves	\$ 53.3	\$ 87.9	\$ 472.7	\$ 645.8	\$ 406.4

As at June 30, 2017, the Company's \$65.0 million senior unsecured bilateral revolving credit facility (the "Corporate Credit Facility") was undrawn and had \$11.7 million of outstanding letters of credit. The facility matures on November 19, 2017 and is subject to customary covenants.

As at June 30, 2017, the Liberty Power Group's committed bank lines consisted of a \$350.0 million senior unsecured syndicated revolving credit facility, a \$150.0 million senior unsecured bilateral revolving credit facility, and a \$88.9 million letter of credit facility (Cdn \$50.0 million and U.S. \$30.0 million). The bilateral revolving credit facility was entered into on April 19, 2017 with a Canadian Chartered Bank and matures on August 19, 2018. As at June 30, 2017, the Liberty Power Group had drawn a total of \$425.9 million and issued \$75.1 million in letters of credit via credit and letters of credit facilities.

As at June 30, 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).

Long Term Debt

On June 28, 2017, in connection with the conclusion of the Montana Water condemnation proceedings (see *Regulatory Proceedings*) the Liberty Utilities Group repaid, using a portion of the proceeds, U.S. \$63.0 million of secured notes without penalty. The notes repaid had an average interest rate of approximately 6.5%. Concurrently Liberty repaid a U.S. \$22.5 million bank term facility.

As at June 30, 2017, the weighted average tenure of APUC's total long term debt is approximately 12 years with an average interest rate of approximately 4.6%.

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.

Contractual Obligations

Information concerning contractual obligations as of June 30, 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	\$ 4,370.7	\$ 210.7	\$ 1,031.3	\$ 582.4	\$ 2,546.3
Convertible debentures	3.2	—	—	—	3.2
Advances in aid of construction	90.3	2.1	—	—	88.2
Interest on long-term debt obligations	1,914.0	184.4	297.7	240.6	1,191.3
Purchase obligations	439.0	439.0	—	—	—
Environmental obligations	93.9	2.6	24.2	7.6	59.5
Derivative financial instruments:					
Cross currency swap	95.7	5.5	10.3	77.8	2.1
Interest rate swap	13.1	—	13.1	—	—
Commodity contracts	3.7	1.8	1.9	—	—
Purchased power	551.8	77.0	100.4	103.9	270.5
Gas delivery, service and supply agreements	415.2	93.6	135.7	78.6	107.3
Service agreements	711.8	46.3	95.0	98.9	471.6
Capital projects	39.5	39.3	0.1	0.1	—
Operating leases	286.2	10.2	19.0	17.8	239.2
Other obligations	196.8	39.5	0.2	0.2	156.9
Total Obligations	\$ 9,224.9	\$ 1,152.0	\$ 1,728.9	\$ 1,207.9	\$ 5,136.1

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 June 30, 2017, APUC had 385,732,932 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 August 9, 2017, \$3.0 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 June 30, 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 June 30, 2017, 65,283,692 common shares representing approximately 17% of total common shares outstanding had been registered with the Reinvestment Plan. During the quarter ended June 30, 2017, 821,936 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on July 14, 2017, an additional 1,194,340 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 \$2.0 billion of specified securities in both Canada and the U.S..

SHARE BASED COMPENSATION PLANS

For the six months ended June 30, 2017, APUC recorded \$4.5 million in total share-based compensation expense as compared to \$2.5 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 June 30, 2017, total unrecognized compensation costs related to non-vested options and share unit awards were \$4.6 million and \$9.5 million, respectively, and are expected to be recognized over a period of 1.79 and 2.24 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 six months ended June 30, 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 June 30, 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 six months ended June 30, 2017, the Company granted (including dividends and performance adjustments) 767,471 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 year a total of 12,115 PSUs were forfeited.

As at June 30, 2017, a total of 968,907 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 six months ended June 30, 2017, the Company issued 34,438 DSUs (including DSUs in lieu of dividends) to the directors of the Company.

As at June 30, 2017, a total of 259,101 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 six months ended June 30, 2017, the Company issued 178,600 common shares to employees under the ESPP.

As at June 30, 2017, a total of 674,630 shares had been issued under the ESPP.

RELATED PARTY TRANSACTIONS

Emera Inc.

An executive at Emera was a member of the Board of APUC until June 8, 2017. During the three and six months ended June 30, 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. \$2.4 million and \$4.6 million as compared to U.S. \$2.9 million and \$5.5 million during the same period in 2016. During the three and six months ended June 30, 2017, the Liberty Utilities Group purchased natural gas amounting to U.S. \$0.2 million and \$1.0 million as compared to U.S. \$0.4 million and \$2.3 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 Q2 2017 with final completion of the contract work expected in Q3 2017. The total cost of the contract is estimated at \$9.5 million. The contract followed a market-based request for proposal process.

There was U.S. \$7.0 million included in accruals for the six months ended June 30, 2017, as compared to U.S. \$0.1 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 and six months ended June 30, 2017, the Company charged its equity-method investees \$0.4 million and \$0.8 million as compared to \$0.9 million and \$1.6 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 June 30, 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 \$296.2 million outstanding as at June 30, 2017. A 100 basis point change in the variable rate charged would impact interest expense by \$3.0 million annually;

- The Liberty Power Group bilateral revolving credit facility is subject to a variable interest rate and had \$129.7 million outstanding as at June 30, 2017. A 100 basis point change in the variable rate charged would impact interest expense by \$1.3 million annually;
- The Liberty Utilities Group revolving credit facility is subject to a variable interest rate and had \$3.9 million outstanding as at June 30, 2017. As a result, a 100 basis point change in the variable rate charged would impact interest expense by \$0.04 million;
- The Liberty Utilities Group commercial paper program is subject to a variable interest rate and had \$20.4 million (U.S. \$15.8 million) outstanding as at June 30, 2017. A 100 basis point change in the variable rate charged would impact interest expense by \$0.2 million annually; and
- The Corporate term credit facility is subject to a variable interest rate and had \$175.2 million (U.S. \$135.0 million) outstanding as at June 30, 2017. A 100 basis point change in the variable rate charged would impact interest expense by \$1.8 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 June 30, 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 and Contractual Risk

Profitability of APUC businesses is, in part, dependent on regulatory regimes in the jurisdictions in which those businesses operate which may be changed from time-to-time. The Company's renewable energy projects can be subject to contractual obligations including the construction milestones under Power Purchase Agreements. Failure to achieve significant milestones could result in assessment of damages and/or termination of the power purchase agreement for projects under development.

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.

Town of Apple Valley Condemnation Proceedings

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 (Measure F) 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, which was passed. 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 peak

in the winter months of January and February and decline 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 June 30, 2017:

(all dollar amounts in \$ millions except per share information)	3rd Quarter 2016	4th Quarter 2016	1st Quarter 2017	2nd Quarter 2017
Revenue	\$ 221.3	\$ 310.2	\$ 557.9	\$ 453.2
Net earnings attributable to shareholders from continuing operations	17.7	46.3	26.0	47.7
Net earnings attributable to shareholders	17.7	46.3	26.0	47.7
Net earnings per share from continuing operations	0.06	0.16	0.07	0.12
Net earnings per share	0.06	0.16	0.07	0.12
Adjusted Net Earnings	26.6	51.4	88.1	53.3
Adjusted Net Earnings per share	0.09	0.18	0.25	0.13
Adjusted EBITDA	91.4	138.3	254.8	197.6
Total assets	6,020.8	8,249.5	10,880.7	10,528.6
Long term debt ¹	2,380.8	4,272.0	4,773.6	4,418.0
Dividend declared per common share	\$ 0.14	\$ 0.14	\$ 0.15	\$ 0.16
	3rd Quarter 2015	4th Quarter 2015	1st Quarter 2016	2nd Quarter 2016
Revenue	\$ 189.6	\$ 260.3	\$ 341.7	\$ 222.8
Net earnings attributable to shareholders from continuing operations	16.7	38.1	42.0	24.8
Net earnings attributable to shareholders	16.5	38.0	42.0	24.8
Net earnings per share from continuing operations	0.06	0.14	0.15	0.08
Net earnings per share	0.05	0.14	0.15	0.08
Adjusted Net Earnings	17.3	39.7	56.1	30.9
Adjusted Net Earnings per share	0.06	0.15	0.21	0.11
Adjusted EBITDA	70.2	109.6	147.9	99.2
Total assets	4,759.0	4,991.7	5,615.5	5,555.0
Long term debt ¹	1,613.3	1,486.8	2,214.5	2,199.9
Dividend declared per common share	\$ 0.13	\$ 0.13	\$ 0.13	\$ 0.14

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 \$47.7 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 June 30, 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 June 30, 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 six months ended June 30, 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 six months ended June 30, 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)

	June 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 31,857	\$ 110,417
Accounts receivable, net (note 4)	237,483	189,658
Fuel and natural gas in storage	50,185	21,625
Supplies and consumables inventory	50,535	15,568
Regulatory assets (note 5)	71,149	48,440
Prepaid expenses	45,811	26,562
Derivative instruments (note 21)	25,104	76,631
Other assets (note 6)	9,608	2,951
	521,732	491,852
Property, plant and equipment, net	8,006,716	4,889,946
Intangible assets, net	62,102	64,989
Goodwill (note 3(a))	1,222,620	306,641
Regulatory assets (note 5)	457,117	243,524
Derivative instruments (note 21)	71,099	74,553
Long-term investments (note 6)	97,401	105,433
Deferred income taxes (note 16)	53,343	30,005
Restricted cash	22,454	2,026,183
Other assets	14,009	16,334
	\$10,528,593	\$ 8,249,460

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	June 30, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	\$ 88,733	\$ 90,592
Accrued liabilities	350,345	308,318
Dividends payable (note 13)	58,316	38,973
Regulatory liabilities (note 5)	65,319	47,769
Long-term debt (note 7)	29,056	10,075
Other long-term liabilities and deferred credits (note 9)	43,844	43,157
Other liabilities (note 21)	13,462	7,665
	649,075	546,549
Long-term debt (note 7)	4,385,808	3,903,340
Convertible debentures (note 10)	3,164	358,619
Regulatory liabilities (note 5)	210,059	134,965
Deferred income taxes (note 16)	882,882	288,139
Derivative instruments (note 21)	105,213	104,647
Pension and other post-employment benefits obligation (note 8)	251,315	147,845
Other long-term liabilities (note 9)	303,861	232,449
Preferred shares, Series C	17,502	17,552
	6,159,804	5,187,556
Redeemable non-controlling interest	61,495	29,434
Equity:		
Preferred shares	213,805	213,805
Common shares (note 11(a))	3,122,630	1,972,203
Additional paid-in capital	36,929	38,652
Deficit	(610,464)	(556,024)
Accumulated other comprehensive income (note 12)	146,140	254,927
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	2,909,040	1,923,563
Non-controlling interests (note 6(a))	749,179	562,358
Total equity	3,658,219	2,485,921
Commitments and contingencies (note 19)		
Subsequent events (notes 5 and 6(a))		
	\$10,528,593	\$ 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 June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Revenue				
Regulated electricity distribution	\$ 238,728	\$ 47,907	\$ 478,793	\$ 111,303
Regulated gas distribution	84,961	68,656	281,080	232,935
Regulated water reclamation and distribution	50,913	47,234	93,843	88,407
Non-regulated energy sales	73,050	54,257	144,808	119,759
Other revenue	5,571	4,708	12,616	12,103
	453,223	222,762	1,011,140	564,507
Expenses				
Operating expenses	162,483	79,280	311,360	164,382
Regulated electricity purchased	68,440	24,754	140,713	63,932
Regulated gas purchased	22,085	14,805	103,530	79,589
Regulated water purchased	3,240	2,967	5,899	5,724
Non-regulated energy purchased	4,995	3,409	12,300	9,024
Administrative expenses	16,660	10,375	31,308	21,793
Depreciation and amortization	84,310	44,809	167,015	94,534
Loss (gain) on foreign exchange	(3,916)	1,875	(3,836)	1,573
	358,297	182,274	768,289	440,551
Operating income	94,926	40,488	242,851	123,956
Interest expense on convertible debentures and acquisition financing (notes 7(b) and 10)	—	16,529	17,638	22,392
Interest expense on long-term debt and others	50,042	16,538	96,967	35,738
Interest, dividend, equity and other income	(2,778)	(2,334)	(6,059)	(4,930)
Other gains	(77)	(4,996)	(78)	(6,212)
Acquisition-related costs (note 3(a))	96	1,196	60,477	7,490
Gain on long-lived assets, net (note 19(a))	(4,846)	(8,794)	(4,823)	(2,609)
Loss (gain) on derivative financial instruments (note 21(b)(iv))	(12)	575	1,370	1,517
	42,425	18,714	165,492	53,386
Earnings before income taxes	52,501	21,774	77,359	70,570
Income tax expense (note 16)				
Current	4,984	2,809	7,568	5,367
Deferred	18,062	2,523	34,850	18,469
	23,046	5,332	42,418	23,836
Net earnings	29,455	16,442	34,941	46,734
Net effect of non-controlling interests (note 15)	(18,260)	(8,355)	(38,733)	(20,099)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	\$ 47,715	\$ 24,797	\$ 73,674	\$ 66,833
Series A and D Preferred shares dividend (note 13)	2,600	2,600	5,200	5,200
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	\$ 45,115	\$ 22,197	\$ 68,474	\$ 61,633
Basic net earnings per share (note 17)	\$ 0.12	\$ 0.08	\$ 0.19	\$ 0.23
Diluted net earnings per share (note 17)	\$ 0.12	\$ 0.08	\$ 0.19	\$ 0.23

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 June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Net earnings	\$ 29,455	\$ 16,442	\$ 34,941	\$ 46,734
Other comprehensive income:				
Foreign currency translation adjustment, net of tax recovery of \$nil and \$nil, respectively (notes 21(b)(iii) and 21(b)(iv))	(104,290)	(23,141)	(141,071)	(181,663)
Change in fair value of cash flow hedges, net of tax expense of \$993 and recovery of \$2,590 (2016 - tax recovery of \$7,572 and \$6,086), respectively (note 21(b)(ii))	(3,662)	(8,287)	1,570	13,279
Change in unrealized appreciation in value of available-for-sale investments	(28)	1	(26)	26
Change in pension and other post-employment benefits, net of tax expense of \$1,197 and \$1,162 (tax recovery of \$2,485 and \$2,393), respectively (note 8)	1,885	(3,863)	1,941	(3,795)
Other comprehensive loss, net of tax	(106,095)	(35,290)	(137,586)	(172,153)
Comprehensive loss	(76,640)	(18,848)	(102,645)	(125,419)
Comprehensive loss attributable to the non-controlling interests	(42,411)	(10,162)	(67,532)	(44,179)
Comprehensive loss attributable to shareholders of Algonquin Power & Utilities Corp.	\$ (34,229)	\$ (8,686)	\$ (35,113)	\$ (81,240)

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 six months ended June 30, 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)	—	—	—	73,674	—	(38,733)	34,941
Redeemable non- controlling interests not included in equity (note 15)	—	—	—	—	—	7,071	7,071
Other comprehensive loss	—	—	—	—	(108,787)	(28,799)	(137,586)
Dividends declared and distributions to non-controlling interests	—	—	—	(107,392)	—	(2,035)	(109,427)
Dividends and issuance of shares under dividend reinvestment plan	18,776	—	—	(18,776)	—	—	—
Common shares issued upon conversion of convertible debentures	1,112,641	—	—	—	—	—	1,112,641
Common shares issued pursuant to share-based awards (note 11(b))	19,010	—	(6,369)	(1,946)	—	—	10,695
Share-based compensation (note 11(b))	—	—	4,646	—	—	—	4,646
Contributions received from non-controlling interests	—	—	—	—	—	249,317	249,317
Balance, June 30, 2017	\$ 3,122,630	\$ 213,805	\$ 36,929	\$ (610,464)	\$ 146,140	\$ 749,179	\$ 3,658,219

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 June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Cash provided by (used in):				
Operating Activities				
Net earnings	\$ 29,455	\$ 16,442	\$ 34,941	\$ 46,734
Adjustments and items not affecting cash:				
Depreciation and amortization	81,303	49,429	171,314	101,270
Deferred taxes	18,062	2,523	34,850	18,469
Unrealized loss on derivative financial instruments	619	6,300	2,982	1,022
Share-based compensation expense	2,206	1,561	4,561	2,634
Cost of equity funds used for construction purposes	(586)	(591)	(1,135)	(1,088)
Pension and post-employment expense	(8,226)	(4,934)	5,713	(2,776)
Non-cash revenue and other income	(46)	(3,985)	(318)	(5,575)
Write-down (gain) on long-lived assets	(4,829)	753	(4,829)	6,938
Changes in non-cash operating items (note 20)	15,402	22,450	(79,275)	(24,249)
	133,360	89,948	168,804	143,379
Financing Activities				
Increase in long-term debt	232,748	4,876	1,514,209	357,171
Decrease in long-term debt	(478,819)	(27,535)	(2,403,161)	(51,979)
Issuance of convertible debentures, net of costs	(27)	352	743,881	358,302
Cash dividends on common shares	(52,893)	(25,212)	(82,849)	(57,819)
Cash dividends on preferred shares	(2,600)	(2,600)	(5,200)	(5,200)
Cash contributions from non-controlling interests	226,228	—	279,633	—
Production-based cash contributions from non-controlling interest	1,498	—	10,622	9,454
Cash distributions to non-controlling interests	(1,195)	(585)	(1,401)	(2,427)
Issuance of common shares, net of costs	68	412	116	681
Proceeds from settlement of derivative assets	—	—	48,380	—
Proceeds from exercise of share options	—	—	12,761	19,493
Shares surrendered to fund withholding taxes on exercised share options	(4,293)	—	(4,293)	(5,218)
Increase in other long-term liabilities	6,197	395	15,805	4,229
Decrease in other long-term liabilities	(2,808)	(556)	(6,383)	(2,821)
	(75,896)	(50,453)	122,120	623,866
Investing Activities				
Increase (decrease) in restricted cash	3,989	(593)	2,010,140	3,949
Acquisitions of operating entities	—	806	(2,047,401)	(332,278)
Divestiture of operating entity (note 19 (a))	111,043	—	111,043	—
Additions to property, plant and equipment	(202,654)	(60,797)	(404,423)	(141,702)
Increase in other assets	(2,012)	(1,902)	(2,749)	(13,123)
Distributions received in excess of equity income	1,750	2,196	390	(570)
Receipt of principal on notes receivable	—	(5)	—	11,685
Increase in long-term investments	(14,283)	(27,733)	(34,177)	(141,945)
	(102,167)	(88,028)	(367,177)	(613,984)
Effect of exchange rate differences on cash	(1,182)	8,493	(2,307)	(8,536)
Increase (decrease) in cash and cash equivalents	(45,885)	(40,040)	(78,560)	144,725
Cash and cash equivalents, beginning of period	77,742	309,118	110,417	124,353
Cash and cash equivalents, end of period	\$ 31,857	\$ 269,078	\$ 31,857	\$ 269,078
Supplemental disclosure of cash flow information:				
	2017	2016	2017	2016
Cash paid during the period for interest expense	\$ 26,598	\$ 30,065	\$ 90,424	\$ 58,922
Cash paid during the period for income taxes	\$ 6,568	\$ 1,779	\$ 8,333	\$ 8,687
Non-cash financing and investing activities:				
Property, plant and equipment acquisitions in accruals	\$ 100,968	\$ 22,337	\$ 100,968	\$ 22,337
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	\$ 10,711	\$ 16,252	\$ 21,002	\$ 19,588
Issuance of common shares upon conversion of convertible debentures (note 10)	\$ 2,007	\$ —	\$ 1,100,362	\$ —

See accompanying notes to unaudited interim consolidated financial statements

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 wind energy assets, wind resources is typically stronger in spring, fall and winter and weaker in summer. 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. 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 June 30, 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	\$ 854,682
Accumulated Depreciation	\$ 228,136
Expenditures	\$ 49,444

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 2017-09, Compensation-Stock Compensation (Topic 718): Scope of Modification Accounting, to provide clarity and reduce both diversity in practice and cost and complexity when applying the guidance in Topic 718, Compensation-Stock Compensation, to a change to the terms or conditions of a share-based payment award. The update clarifies that an entity should account for the effects of a modification unless all of the following are met: (1) the fair value of the modified award is the same as the fair value of the original award immediately before the original award is modified, (2) the vesting conditions of the modified award are the same as the vesting conditions of the original award immediately before the original award was modified, and (3) the classification of the modified award as an equity instrument or a liability instrument is the same as the classification of the original award immediately before the original award is modified. The update is effective for fiscal years and interim periods, beginning after December 15, 2017. Early adoption is permitted.

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

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.

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 identified and documented details for contracts that could be impacted by the new revenue recognition standard. The Company is currently in the process of finalizing the impact assessment and determining the method of adoption. This stage will be followed by an evaluation of the impact on internal controls and financial statement disclosures. The Company is on track for implementation of this standard by the effective date.

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.

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	\$ 52,084
Property, plant and equipment	2,763,746
Goodwill	993,907
Regulatory assets	270,987
Other assets	50,750
Long-term debt	(1,218,563)
Regulatory liabilities	(104,783)
Pension and other post-employment benefits	(107,907)
Deferred income tax liability, net	(574,276)
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 and six months ended ended June 30, 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 June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Revenues	\$ 453,223	\$ 401,870	\$ 1,011,140	\$ 951,544
Net earnings attributable to common shareholders	\$ 45,903	\$ 63,242	\$ 125,602	\$ 139,633

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.

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. During a six-month period in year 2022, the tax investor has the right to withdraw from Luning Holdings and require the Company to redeem its remaining interests for cash. As a result, 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 June 30, 2017.

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.

(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 June 30, 2017 include unbilled revenue of \$53,563 (December 31, 2016 - \$57,822) from the Company's regulated utilities. Accounts receivable as of June 30, 2017 are presented net of allowance for doubtful accounts of \$8,969 (December 31, 2016 - \$7,064).

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. Empire also provides regulated water utility distribution services 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 unaudited interim consolidated financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period.

In April 2017, the State of Iowa Department of Commerce Utilities Board approved a rate increase of U.S. \$1,000 for the Midstates Gas system effective June 18, 2017.

In May 2017, the Illinois Commerce Commission approved a rate increase of U.S. \$2,200 for the Midstates Gas system effective June 7, 2017.

In April 2017, the EnergyNorth Gas System filed for a distribution rate case with the New Hampshire Public Utility Commission. On June 30, 2017, the Commission approved a temporary revenue increase of U.S. \$6,750, effective July 1, 2017 which are to remain in place until the end of the Company's permanent rate case.

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. 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 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.

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.

Notes to the Unaudited Interim Consolidated Financial Statements

June 30, 2017 and 2016

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

Regulatory assets and liabilities consist of the following:

	June 30, 2017	December 31, 2016
Regulatory assets		
Environmental remediation	\$ 101,540	\$ 104,160
Pension and post-employment benefits	143,178	75,527
Debt premium	76,557	25,173
Fuel and commodity costs adjustments	20,273	6,972
Rate adjustment mechanism	43,775	40,602
Clean Energy and other customer programs	25,550	2,106
Deferred construction costs (a)	18,796	—
Asset retirement	19,336	2,113
Income taxes	32,558	10,182
Rate case costs	10,743	8,572
Other	35,960	16,557
Total regulatory assets	\$ 528,266	\$ 291,964
Less current regulatory assets	(71,149)	(48,440)
Non-current regulatory assets	\$ 457,117	\$ 243,524
Regulatory liabilities		
Cost of removal	\$ 156,424	\$ 110,330
Rate-base offset	18,653	20,946
Fuel and commodity costs adjustments	46,761	33,891
Deferred compensation received in relation to lost production	13,712	—
Deferred construction costs - fuel related (a)	9,702	—
Pension and post-employment benefits	9,002	5,481
Income Taxes	6,561	1,501
Other	14,563	10,585
Total regulatory liabilities	\$ 275,378	\$ 182,734
Less current regulatory liabilities	(65,319)	(47,769)
Non-current regulatory liabilities	\$ 210,059	\$ 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.

6. Long-term investments

Long-term investments consist of the following:

	June 30, 2017	December 31, 2016
Equity-method investees		
Red Lily	\$ 24,682	\$ 23,504
Deerfield Wind Project (a)	—	34,727
Amherst Island Wind Project	1,078	558
Other	3,467	5,630
	\$ 29,227	\$ 64,419
Notes receivable		
Development loans (b)	\$ 63,916	\$ 32,125
Other	5,954	6,058
	69,870	38,183
Available-for-sale investment	—	169
Other investments	2,610	2,662
Total long-term investments	101,707	105,433
Less current portion classified within other assets	(4,306)	—
Total long-term investments	\$ 97,401	\$ 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. Construction was completed during the first quarter and sale of power to the utility under the power purchase agreement started on February 21, 2017. 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

6. Long-term investments (continued)

(b) Development loans

As at June 30, 2017, the Company has a loan and credit support facility with Windlectric Inc. Windlectric Inc. ("Windlectric") owns a 75 MW construction-stage wind development project ("Amherst Island Wind Project") in the province of Ontario. 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 Amherst Island Wind Project. The loan bears interest at an annual rate of 10% on outstanding principal amount and matures on December 31, 2018.

During the second quarter, the Company also provided a one-year loan of U.S. \$3,318 to a wind developing project company.

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	June 30, 2017	December 31, 2016
Senior Unsecured Revolving Credit Facilities (a)	\$ 429,830	\$ 242,947
Senior Unsecured Bank Credit Facilities (b)	175,190	2,140,122
Commercial Paper (c)	20,439	—
Canadian Dollar Borrowings		
Senior Unsecured Notes (d)	780,646	487,389
Senior Secured Project Notes	34,544	35,600
U.S. Dollar Borrowings		
Senior Unsecured Notes (e)	1,644,643	700,600
Senior Unsecured Utility Notes (f)	321,293	174,206
Senior Secured Utility Bonds (g)	1,008,279	132,551
	\$ 4,414,864	\$ 3,913,415
Less: current portion	(29,056)	(10,075)
	\$ 4,385,808	\$ 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.

Short-term obligations of U.S. \$140,000 that are expected to be refinanced using the long-term credit facilities are presented as long-term debt.

(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 (note 7(b)).

7. Long-term debt (continued)**(a) Senior unsecured revolving credit facilities (continued)**

During the quarter, the Liberty Power Group entered into a \$150,000 bilateral revolving credit facility. The maturity date of May 19, 2018 was amended, subsequent to quarter end, to August 19, 2018.

(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(e)).

In June 2017, the Company repaid a U.S. \$22,500 bank term facility related to Park Water systems.

(c) Commercial Paper

In connection with the acquisition of Empire (note 3(a)), the Company assumed a short-term commercial paper program.

(d) 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.

(e) 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%.

(f) 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%.

(g) 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%.

In June 2017, outstanding bonds payable for the Park Water systems in the amount of U.S. \$63,000 were repaid using proceeds from the Mountain Water condemnation discussed in note 19(a).

(h) 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. 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 other post-employment benefits ("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.

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.

On June 22, 2017, all Mountain Water employees were terminated as a result of the condemnation of the Mountain Water assets to the city of Missoula (note 19(a)). The pension and OPEB obligations of these employees remain with the Company. The assets and projected benefit obligations of the plans were revalued at June 30, 2017 and resulted in an actuarial gain of U.S. \$2,354 recorded in other comprehensive income and a curtailment gain of U.S. \$853 recorded against the loss on long-lived assets.

The following tables list the components of net benefit costs for pension and 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			
	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Service cost	\$ 4,841	\$ 2,320	\$ 9,604	\$ 4,350
Interest cost	6,706	3,052	13,303	6,428
Expected return on plan assets	(8,483)	(3,464)	(16,828)	(6,975)
Amortization of net actuarial loss	359	858	713	1,515
Amortization of prior service credits	(209)	(233)	(415)	(384)
Amortization of regulatory asset/liability	4,219	1,071	7,741	2,213
Net benefit cost	\$ 7,433	\$ 3,604	\$ 14,118	\$ 7,147

8. Pension and other post-employment benefits (continued)

	OPEB			
	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Service cost	\$ 1,718	\$ 809	\$ 3,409	\$ 1,623
Interest cost	2,249	926	4,461	1,847
Expected return on plan assets	(2,179)	(289)	(4,322)	(608)
Amortization of net actuarial loss	(48)	147	(96)	278
Amortization of prior service credits	(88)	(447)	(174)	(924)
Amortization of regulatory asset/liability	545	235	716	503
Net benefit cost	\$ 2,197	\$ 1,381	\$ 3,994	\$ 2,719

9. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

	June 30, 2017	December 31, 2016
Advances in aid of construction	\$ 90,237	\$ 105,191
Environmental remediation obligations	64,460	63,378
Asset retirement obligations	58,211	24,822
Customer deposits	34,838	14,881
Unamortized investment tax credits	23,428	—
Hook up fees	13,202	12,039
Deferred income	1,500	—
Deferred credits	27,342	44,544
Other	34,487	10,751
	347,705	275,606
Less current portion	(43,844)	(43,157)
	\$ 303,861	\$ 232,449

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	743,881
Amortization of deferred financing costs	1,026
Conversion to common shares	\$ (1,100,362)
Carrying value at June 30, 2017	\$ 3,164
Face value at June 30, 2017	\$ 3,305

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 \$743,881, 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 and six months ended June 30, 2017 is \$nil and \$9,373 (2016 - \$14,335 and \$19,219).

The debentures are convertible into up to 108,490,566 common shares. As at June 30, 2017, a total of 108,178,779 common shares of the Company were issued (note 11), representing conversion into common shares of more than 99.71% 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.

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)	108,178,779
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	1,997,773
Common shares, end of period	385,732,932

11. Shareholders' capital (continued)**(b) Share-based compensation**

During the six months ended June 30, 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

During the first quarter, 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.

During the first quarter, 253,809 Performance Share Units ("PSU") were granted to executives of the Company. The PSUs vest on January 1, 2020. During the second quarter, 358,307 PSU were granted to employees of the Company. The PSUs vest on January 1, 2020. During the first 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 six months period ended June 30, 2017, 28,684 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 and six months ended June 30, 2017, APUC recorded \$2,260 and \$4,515 (2016 -\$1,483 and \$2,493) 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 June 30, 2017, total unrecognized compensation costs related to non-vested options and PSUs were \$4,599 and \$9,482, respectively, and are expected to be recognized over a period of 1.79 and 2.24 years, respectively.

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	(112,272)	5,228	(26)	1,914	(105,156)
Amounts reclassified	—	(3,658)	—	27	(3,631)
Net current period OCI	\$(112,272)	\$ 1,570	\$ (26)	\$ 1,941	\$(108,787)
Balance, June 30, 2017	\$ 88,056	\$ 67,653	\$ 115	\$ (9,684)	\$ 146,140

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 three and six months ended June 30, 2017 and 2016 were as follows:

	Three Months Ended June 30			
	2017		2016	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	\$ 61,573	\$ 0.1593	\$ 37,242	\$ 0.1361
Series A preferred shares	\$ 1,350	\$ 0.2813	\$ 1,350	\$ 0.2813
Series D preferred shares	\$ 1,250	\$ 0.3125	\$ 1,250	\$ 0.3125

	Six Months Ended June 30			
	2017		2016	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	\$ 120,968	\$ 0.3126	\$ 72,202	\$ 0.2648
Series A preferred shares	\$ 2,700	\$ 0.5625	\$ 2,700	\$ 0.5625
Series D preferred shares	\$ 2,500	\$ 0.6250	\$ 2,500	\$ 0.6250

14. Related party transactions
Emera Inc.

An executive at Emera was a member of the Board of APUC until June 8, 2017. During the three and six months ended June 30, 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. \$2,365 and \$4,586 (2016 - U.S. \$2,935 and \$5,541). During the three and six months ended June 30, 2017, the Liberty Utilities Group purchased natural gas amounting to U.S. \$160 and \$1,006 (2016 - U.S. \$368 and \$2,281) 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 Q2 2017 with final completion of the contract work expected in the third quarter. The total cost of the contract is estimated at \$9,500. The contract followed a market based request for proposal process.

There was U.S. \$6,997 included in accruals for the six months ended June 30, 2017 (2016 - U.S. \$54) 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, the Company charged its equity-method investees \$369 and \$808 (2016 - \$869 and \$1,617) during the three and six months ended June 30, 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 and six months ended June 30, 2017 and 2016 consists of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
HLBV and other adjustments attributable to:				
Non-controlling interest -Class A partnership units	\$ (15,458)	\$ (7,400)	\$ (33,443)	\$ (19,443)
Non-controlling interest -redeemable Class A partnership units	(3,522)	(1,361)	(7,071)	(2,749)
Other net earnings attributable to non-controlling interests	720	406	1,781	2,093
Net effect of non-controlling interests	\$ (18,260)	\$ (8,355)	\$ (38,733)	\$ (20,099)

16. Income taxes

For the six months ended June 30, 2017, the Company's overall effective tax rate was different from the statutory Canadian income tax rate of 26.50% (2016 - 26.50%) primarily due to transaction costs related to the acquisition of Empire, basis differences related to the Mountain Water condemnation, and higher tax rates on U.S. earnings.

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 quarter-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.

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 and six months ended June 30, 2017 and 2016 are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Net earnings attributable to shareholders of APUC	\$ 47,715	\$ 24,797	\$ 73,674	\$ 66,833
Series A Preferred shares dividend	1,350	1,350	2,700	2,700
Series D Preferred shares dividend	1,250	1,250	2,500	2,500
Net earnings attributable to common shareholders of APUC – Basic and Diluted	\$ 45,115	\$ 22,197	\$ 68,474	\$ 61,633
Weighted average number of shares				
Basic	385,486,772	271,570,250	364,634,149	270,068,016
Effect of dilutive securities	3,682,452	1,954,574	3,824,012	2,760,721
Diluted	389,169,224	273,524,824	368,458,161	272,828,737

The shares potentially issuable, for the three and six months ended June 30, 2017, as a result of 2,328,343 and 1,678,156 share options (2016 - 2,402,637 and 2,467,015) 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.

Notes to the Unaudited Interim Consolidated Financial Statements

June 30, 2017 and 2016

*(in thousands of Canadian dollars, except as noted and per share amounts)***18. Segmented information (continued)****Three Months Ended June 30, 2017**

	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	\$ 76,664	\$ 376,559	\$ —	\$ 453,223
Fuel, power and water purchased	4,995	93,765	—	98,760
Net revenue	71,669	282,794	—	354,463
Operating expenses	23,040	139,443	—	162,483
Administrative expenses	6,415	10,703	(458)	16,660
Depreciation and amortization	27,321	56,655	334	84,310
Gain on foreign exchange	—	—	(3,916)	(3,916)
Operating income	14,893	75,993	4,040	94,926
Interest expense	12,768	36,708	566	50,042
Interest, dividend, equity and other income	(695)	(1,167)	(916)	(2,778)
Other expenses (gain)	713	(5,622)	70	(4,839)
Earnings before income taxes	\$ 2,107	\$ 46,074	\$ 4,320	\$ 52,501
Capital expenditures	99,413	103,241	—	202,654

Three Months Ended June 30, 2016

	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	\$ 58,957	\$ 163,805	\$ —	\$ 222,762
Fuel and power purchased	3,409	42,526	—	45,935
Net revenue	55,548	121,279	—	176,827
Operating expenses	18,501	60,764	15	79,280
Administrative expenses	4,142	5,995	238	10,375
Depreciation and amortization	18,997	23,883	1,929	44,809
Loss on foreign exchange	—	—	1,875	1,875
Operating income (loss)	13,908	30,637	(4,057)	40,488
Interest expense	3,812	12,397	16,858	33,067
Interest, dividend and other income	(207)	(1,437)	(690)	(2,334)
Other expense (gain)	(13,124)	754	351	(12,019)
Earnings (loss) before income taxes	\$ 23,427	\$ 18,923	\$ (20,576)	\$ 21,774
Capital expenditures	18,843	41,954	—	60,797

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

June 30, 2017 and 2016

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

Six Months Ended June 30, 2017				
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	\$ 153,366	\$ 857,774	\$ —	\$ 1,011,140
Fuel, power and water purchased	12,300	250,142	—	262,442
Net revenue	141,066	607,632	—	748,698
Operating expenses	42,241	269,119	—	311,360
Administrative expenses	10,706	20,171	431	31,308
Depreciation and amortization	53,517	112,831	667	167,015
Gain on foreign exchange	—	—	(3,836)	(3,836)
Operating income	34,602	205,511	2,738	242,851
Interest expense	23,826	64,126	26,653	114,605
Interest, dividend, equity and other income	(1,915)	(2,489)	(1,655)	(6,059)
Other expenses (gain)	2,300	(5,806)	60,452	56,946
Earnings (loss) before income taxes	\$ 10,391	\$ 149,680	\$ (82,712)	\$ 77,359
Property, plant and equipment	\$ 2,871,695	\$ 5,091,110	\$ 43,911	\$ 8,006,716
Equity-method investees	26,029	1,037	2,161	29,227
Total assets	3,154,088	7,255,414	119,091	10,528,593
Capital expenditures	118,439	285,984	—	404,423

Six Months Ended June 30, 2016				
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	\$ 131,319	\$ 433,188	\$ —	\$ 564,507
Fuel and power purchased	9,024	149,245	—	158,269
Net revenue	122,295	283,943	—	406,238
Operating expenses	34,781	129,571	30	164,382
Administrative expenses	9,048	11,478	1,267	21,793
Depreciation and amortization	40,385	52,220	1,929	94,534
Gain on foreign exchange	—	—	1,573	1,573
Operating income (loss)	38,081	90,674	(4,799)	123,956
Interest expense	9,755	25,135	23,240	58,130
Interest, dividend and other income	(721)	(2,656)	(1,553)	(4,930)
Other expense (gain)	(12,835)	6,802	6,219	186
Earnings (loss) before income taxes	\$ 41,882	\$ 61,393	\$ (32,705)	\$ 70,570
Capital expenditures	61,239	80,463	—	141,702

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

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 was 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 could proceed with condemnation of Mountain Water's assets. The fair market value of the condemned property as of May 6, 2014 was assessed by the Commissioners to be U.S. \$88,600. Upon taking possession of Mountain Water's assets on June 22, 2017, the city of Missoula paid U.S. \$83,863 to Mountain Water, net of closing adjustments and amounts required to be paid by the City directly to various developers in satisfaction of obligations under Funded By Other (FBO) contracts relating to the assets.

In connection with Liberty Utilities' indirect acquisition of Mountain Water in January 2016, Liberty Utilities was permitted and continues to hold-back U.S. \$14,400 from the purchase price otherwise payable to Carlyle Infrastructure Partners, L.P. ("Carlyle") and certain other interest holders.

The condemnation of the Mountain Water assets resulted in a gain on long-lived assets of U.S. \$4,508

(b) Commitments

In addition to the commitments related to the development projects disclosed in note 6, the following significant commitments exist as of June 30, 2017.

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

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)	\$ 76,966	\$ 49,507	\$ 50,851	\$ 51,800	\$ 52,087	\$ 270,546	\$ 551,757
Gas supply and service agreements (ii)	93,596	74,534	61,167	46,634	31,948	107,301	415,180
Service agreements	46,275	46,413	48,594	49,819	49,101	471,620	711,822
Capital projects	39,265	66	67	67	67	17	39,549
Operating leases	10,154	9,907	9,052	8,877	8,960	239,191	286,141
Total	\$266,256	\$180,427	\$169,731	\$157,197	\$142,163	\$1,088,675	\$2,004,449

19. Commitments and contingencies (continued)

(b) Commitments (continued)

- (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 June 30, 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 June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Accounts receivable	\$ 51,395	\$ 39,600	\$ 64,588	\$ 53,219
Fuel and natural gas in storage	(7,860)	(3,504)	3,563	13,117
Supplies and consumable inventory	1,363	195	303	505
Income taxes receivable	(1,077)	5,459	(2,210)	1,697
Prepaid expenses	(5,291)	(1,861)	(6,411)	(5,833)
Accounts payable	3,618	(4,743)	(81,682)	(40,449)
Accrued liabilities	(12,807)	(3,322)	(35,746)	(39,521)
Current income tax liability	(281)	(4,297)	696	(4,901)
Net regulatory assets and liabilities	(13,658)	(5,077)	(22,376)	(2,083)
	\$ 15,402	\$ 22,450	\$ (79,275)	\$ (24,249)

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

June 30, 2017 and 2016

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

(a) Fair value of financial instruments

June 30, 2017	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	\$ 69,870	\$ 71,026	\$ —	\$ 71,026	\$ —
Derivative instruments:					
Energy contracts designated as a cash flow hedge	83,110	83,110	—	—	83,110
Currency forward contract not designated as a hedge	24	24	—	24	—
Commodity contracts for regulated operations	315	315	—	315	—
Transmission congestion rights	12,282	12,282	—	12,282	—
Total derivative instruments	95,731	95,731	—	12,621	83,110
Total financial assets	\$ 165,601	\$ 166,757	\$ —	\$ 83,647	\$ 83,110
Long-term debt	\$ 4,414,864	\$ 4,445,763	\$ 828,276	\$ 3,617,487	\$ —
Convertible debentures	3,164	3,305	3,305	—	—
Preferred shares, Series C	18,455	18,746	—	18,746	—
Derivative instruments:					
Cross-currency swap designated as a net investment hedge	95,767	95,767	—	95,767	—
Interest rate swap designated as a hedge	13,122	13,122	—	13,122	—
Currency forward contract not designated as a hedge	889	889	—	889	—
Commodity contracts for regulated operations	3,635	3,635	—	3,635	—
Total derivative instruments	113,413	113,413	—	113,413	—
Total financial liabilities	\$ 4,549,896	\$ 4,581,227	\$ 831,581	\$ 3,749,646	\$ —

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

June 30, 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:					
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	\$ —

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 June 30, 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 \$22.45 to \$133.21 with a weighted average of \$34.99 as of June 30, 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 or six months ended June 30, 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	885,045
Options	858,077
Forward contracts	15,060,000
	16,803,122

At June 30, 2017, transmission congestion rights ("TCR") of 9,141 monthly MWH have been obtained from TCR auctions to hedge 2017 congestion costs in the Southwest Power Pool ("SPP") Integrated Marketplace.

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:

	June 30, 2017	December 31, 2016
Regulatory assets:		
Swap contracts	U.S. \$ 91	U.S. \$ —
Option contracts	U.S. \$ 213	U.S. \$ 27
Forward contracts	U.S. \$ 4,845	U.S. \$ —
Regulatory liabilities:		
Swap contracts	U.S. \$ 5	U.S. \$ 175
Option contracts	U.S. \$ —	U.S. \$ 92
Forward contracts	U.S. \$ 15,548	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)
621,753	December 2022	U.S. \$ 42.81	PJM Western HUB
2,658,758	December 2022	U.S. \$ 30.25	NI HUB
3,469,296	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(e)). 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. \$nil and U.S. \$36,533 and for the three and six months ended June 30, 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 gain of \$1,342 and \$263 for the three and six months ended June 30, 2017 (2016 - loss of \$5,634 and gain of \$14,786), which was recorded in OCI.

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 June 30		Six months ended June 30	
	2017	2016	2017	2016
Effective portion of cash flow hedge	\$ (2,273)	\$ (6,566)	\$ 5,245	\$ 18,568
Amortization of cash flow hedge	(8)	(7)	(17)	(17)
Gain reclassified from AOCI	(1,381)	(1,714)	(3,658)	(5,272)
OCI attributable to shareholders of APUC	\$ (3,662)	\$ (8,287)	\$ 1,570	\$ 13,279

The Company expects \$12,021 and \$2,734 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 and \$nil for the three and six months ended June 30, 2017 (2016 - \$nil and \$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 Liberty Power 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 and six months ended June 30, 2017, a gain of \$3,191 and a loss of \$4,978 (2016 - loss of \$4,183 and \$11,415) 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 though 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.

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 June 30, 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 \$nil and \$1,452 and a loss of \$nil and \$17,864 for three and six months ended June 30, 2017, which is recorded as loss on foreign exchange in the unaudited interim consolidated statements of operations (2016 - \$nil and \$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 is mitigated through the use of currency forward contracts. For the three and six months ended June 30, 2017, a loss on foreign exchange of \$1,017 and \$889 (2016 - \$nil and \$nil) was recorded in the unaudited interim consolidated statements of operations. These currency forward contracts are 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.

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 June 30		Six Months Ended June 30	
	2017	2016	2017	2016
Change in unrealized loss (gain) on derivative financial instruments:				
Energy derivative contracts	\$ —	\$ —	\$ —	\$ (426)
Currency forward contracts	992	5,668	865	418
Total change in unrealized loss (gain) on derivative financial instruments	\$ 992	\$ 5,668	\$ 865	\$ (8)
Realized loss (gain) on derivative financial instruments:				
Interest rate swaps	—	—	(193)	—
Energy derivative contracts	—	(29)	730	941
Currency forward contracts	—	(5,600)	16,413	(5,600)
Total realized loss (gain) on derivative financial instruments	\$ —	\$ (5,629)	\$ 16,950	\$ (4,659)
Loss (gain) on derivative financial instruments not accounted for as hedges	992	39	17,815	(4,667)
Ineffective portion of derivative financial instruments accounted for as hedges	(12)	604	833	1,002
	\$ 980	\$ 643	\$ 18,648	\$ (3,665)
Amounts recognized in the consolidated statements of operations consist of:				
Loss (gain) on derivative financial instruments	\$ (12)	\$ 575	\$ 1,370	\$ 1,517
Loss (gain) on foreign exchange	\$ 992	\$ 68	\$ 17,278	\$ (5,182)
	\$ 980	\$ 643	\$ 18,648	\$ (3,665)

(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.

Notes

Notes

Notes

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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