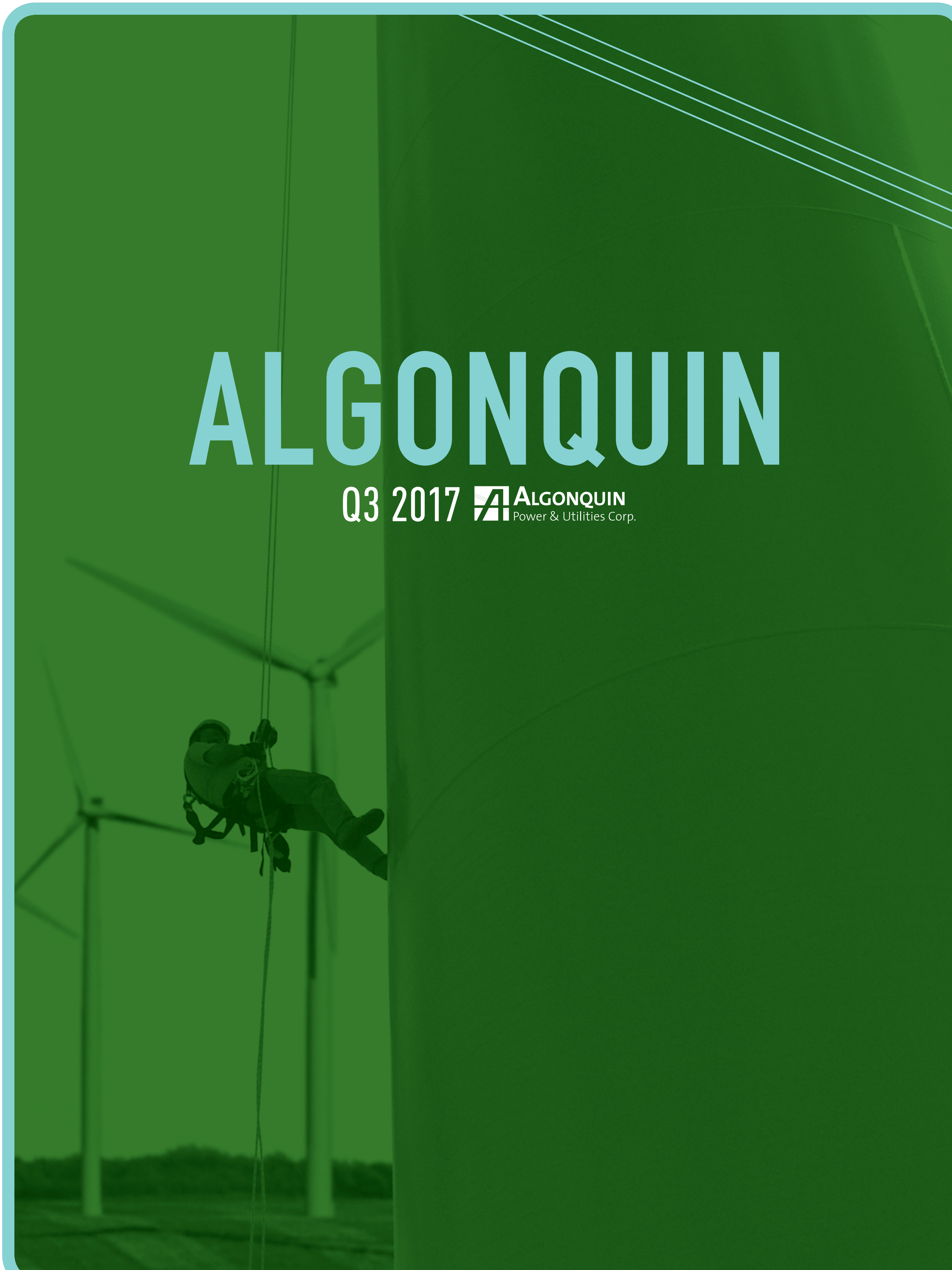
ALGONQUIN

Q3 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.

Algonquin Power & Utilities Corp.

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ALGONQUIN
Power & Utilities Corp.

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 nine months ended September 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 nine months ended September 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 November 14, 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" 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 and are 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 November 10, 2017, the quarterly dividend is equivalent to Cdn $0.1478 per common share or Cdn $0.5909 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 758,000 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 264,000 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 159,000 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

Investment in Joint Venture with Abengoa and Purchase of 25% Interest in Atlantica Yield plc

On November 1, 2017, APUC entered into an agreement to create a joint venture ("AAGES") with Seville, Spain-based Abengoa, S.A (MCE: ABG) ("Abengoa") to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Concurrently with the creation of the AAGES joint venture, APUC entered into a definitive agreement to purchase from Abengoa a 25% equity interest in Atlantica Yield plc ("Atlantica") for a total purchase price of approximately U.S. $608 million, based on a price of U.S. $24.25 per ordinary share of Atlantica, plus a contingent payment of up to U.S. $0.60 per-share payable two years after closing, subject to certain conditions. The transaction is expected to close in the first quarter of 2018, subject to regulatory approvals and other closing conditions. No shareholder approvals are required.

$576 Million Bought Deal Offering of Common Shares

On November 10, 2017, APUC announced that it closed a bought deal offering announced on November 1, 2017, including the exercise in full of the underwriters' over-allotment option. As a result a total of 43,470,000 common shares of APUC were sold at a price of $13.25 per share for gross proceeds of approximately $576.0 million.

Net proceeds of the offering are expected to be used, in part, to finance APUC's acquisition of a 25% ownership stake in Atlantica from Abengoa and for general corporate purposes.

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.

	Three Months Ended September 30		
(all dollar amounts in $ millions except per share information)	2017	2016	Change
Net earnings attributable to shareholders	**$ 59.4**	$ 17.7	**236%**
Adjusted Net Earnings	**$ 64.9**	$ 26.6	**144%**
Adjusted EBITDA	**$ 197.5**	$ 91.4	**116%**
Net earnings per common share	**$ 0.15**	$ 0.06	**150%**
Adjusted Net Earnings per common share	**$ 0.16**	$ 0.09	**78%**

Declaration of Canadian Equivalent Fourth Quarter Dividend of Cdn $0.1478 (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:

	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Total
U.S. dollar dividend	$0.1165	$0.1165	$0.1165	$0.1165	$0.4660
Canadian dollar equivalent	$0.1533	$0.1593	$0.1480	$0.1478	$0.6084

Liberty Utilities Group Highlights

Approval to acquire the Perris Water Distribution System

On August 10, 2017 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 Utilities 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 Utilities. The City of Perris residents voted to approve the sale on November 7, 2017. Liberty Utilities will now file an application to acquire the water utility with the California Public Utility Commission. Approval of the acquisition of the utility is expected in 2018.

Acquisition of the St. Lawrence Gas Company, Inc.

On August 31, 2017 the Company entered into a definitive agreement to acquire St. Lawrence Gas Company, Inc. ("SLG"). SLG is a rate-regulated natural gas distribution utility serving approximately 16,000 customers in northern New York State. The total purchase price for the transaction is U.S. $70.0 million, less total third-party debt of SLG outstanding at closing, and subject to customary working capital adjustments. Closing of the transaction remains subject to regulatory approval and other closing conditions and is expected to occur in late 2018 or early 2019.

2017 Third Quarter Results From Operations

Key Financial Information	Three Months Ended September 30	
(all dollar amounts in $ millions except per share information)	2017	2016
Revenue	**$ 443.3**	$ 221.3
Net earnings attributable to shareholders	**59.4**	17.7
Cash provided by operating activities	**119.1**	22.6
Adjusted Net Earnings[1]	**64.9**	26.6
Adjusted EBITDA[1]	**197.5**	91.4
Adjusted Funds from Operations[1]	**127.0**	61.0
Dividends declared to common shareholders	**57.5**	37.7
Weighted average number of common shares outstanding	**386,816,307**	273,202,368
Per share		
Basic net earnings	**$ 0.15**	$ 0.06
Diluted net earnings	**$ 0.15**	$ 0.05
Adjusted Net Earnings[1,2]	**$ 0.16**	$ 0.09
Dividends declared to common shareholders	**$ 0.15**	$ 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 September 30, 2017, APUC experienced an average U.S. exchange rate of approximately 1.2526 as compared to 1.3047 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 September 30, 2017, APUC reported total revenue of $443.3 million as compared to $221.3 million during the same period in 2016, an increase of $222.0 million. The major factors resulting in the increase in APUC revenue in the three months ended September 30, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in $ millions)		Three Months Ended September 30
Comparative Prior Period Revenue	**$**	**221.3**
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO as well as a decline in production in the Maritimes region and lower average market rates in the Western region.		(5.7)
Wind Canada: Increase primarily due to higher production and annual rate increases.		0.1
Wind U.S.: Decrease primarily due to lower production.		(1.2)
Solar U.S.: Decrease primarily due to lower production.		(0.2)
Thermal: Increase primarily due to increased pricing at the Sanger Thermal Facility which is partially offset by a decline in production.		0.4
Other:		(0.5)
		(7.1)
New Facilities		
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.		7.1
Solar U.S.: Bakersfield II Solar Facility was placed in service in December 2016.		0.8
		7.9
Foreign Exchange		**(1.4)**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease primarily due to lower cost of energy at the Calpeco Electric System combined with lower volumes at the Granite State Electric System due to decreased cooling degree days.		(1.3)
Gas: Increase primarily due to higher purchased gas costs at the Peach State Gas Systems combined with higher volumes at the Midstates, EnergyNorth and Peach State Gas Systems.		4.3
Water: Decrease primarily due to completion of condemnation proceedings on June 22, 2017 of the Mountain Water System in Montana.		(3.6)
Other: Decrease primarily due to lower contracted services.		(4.5)
		(5.1)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($214.5 million) on January 1, 2017 and the Luning Solar Facility ($3.9 million) on February 15, 2017.		218.4
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		5.9
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.7
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		2.1
		227.1
Rate Cases		
Electricity: Implementation of new rates at the Calpeco and Granite State Electric Systems.		3.7
Gas: Implementation of new rates at the EnergyNorth, Peach State, and New England Gas Systems.		1.8
Water: Implementation of new rates at the Park Water (Central Basin), Apple Valley Water, and Rio Rico Water Systems.		1.8
		7.3
Foreign Exchange		**(6.7)**
Current Period Revenue	**$**	**443.3**

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

For the three months ended September 30, 2017, net earnings attributable to shareholders totaled $59.4 million as compared to $17.7 million during the same period in 2016, an increase of $41.7 million or 235.6%. The increase was primarily due to a $103.3 million increase in earnings from operating facilities (including Empire), $1.0 million decrease in acquisition related costs, $1.0 million increase in interest, dividend equity and other income, and $7.5 million increase in net effect of non-controlling interests. These items were partially offset by a $6.0 million decrease in foreign exchange gain, $4.4 million decrease in gains from derivative instruments, $0.6 million decrease in gains on long lived assets, $2.3 million decrease in other gains, $2.3 million increase in administration charges, $31.7 million increase in depreciation and amortization expenses, $10.8 million increase in interest expense, and $13.0 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)*.

During the three months ended September 30, 2017, cash provided by operating activities totaled $119.1 million as compared to cash provided by operating activities of $22.6 million during the same period in 2016. During the three months ended September 30, 2017, Adjusted Funds from Operations totaled $127.0 million compared to Adjusted Funds from Operations of $61.0 million during the same period in 2016. The change in Adjusted Funds from Operations in the three months ended September 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 September 30, 2017, Adjusted EBITDA totaled $197.5 million as compared to $91.4 million during the same period in 2016, an increase of $106.1 million or 116.1%. 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 (all dollar amounts in $ millions except per share information)	Nine Months Ended September 30 **2017**	**2016**
Revenue	**$ 1,454.5**	$ 785.8
Net earnings attributable to shareholders	**133.1**	84.6
Cash provided by operating activities	**288.0**	166.0
Adjusted Net Earnings[1]	**206.2**	114.0
Adjusted EBITDA[1]	**650.0**	338.6
Adjusted Funds from Operations[1]	**455.4**	260.0
Dividends declared to common shareholders	**178.5**	109.9
Weighted average number of common shares outstanding	**372,109,455**	271,120,426
Per share		
Basic net earnings	**$ 0.34**	$ 0.28
Diluted net earnings	**$ 0.33**	$ 0.28
Adjusted Net Earnings[1,2]	**$ 0.53**	$ 0.40
Dividends declared to common shareholders	**$ 0.46**	$ 0.40
	As at	
	September 30, 2017	**December 31, 2016**
Total assets	**$ 10,306.7**	$ 8,249.5
Long term debt[3]	**$ 4,435.1**	$ 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 nine months ended September 30, 2017, APUC experienced an average U.S. exchange rate of approximately 1.3068 as compared to 1.3224 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 nine months ended September 30, 2017, APUC reported total revenue of $1.5 billion as compared to $785.8 million during the same period in 2016, an increase of $668.7 million or 85.1%. The major factors resulting in the increase in APUC revenue for the nine months ended September 30, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in $ millions)		Nine Months Ended September 30
Comparative Prior Period Revenue	**$**	**785.8**
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO, a decline in production in the Maritimes region and lower average market rates in the Western region.		(7.1)
Wind Canada: Increase primarily due to slight increase in production and annual rate increases.		0.3
Wind U.S.: Decrease primarily due to lower REC pricing partially offset by higher production.		(0.6)
Solar Canada: Decrease due to lower production.		(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.		(0.5)
Thermal: Increase due to higher pass-through costs to customer as a result of higher fuel costs, partially offset by decreased production.		1.2
Other: Decrease primarily due to a new capacity-based contract at the Sanger Thermal Facility.		(1.7)
		(9.0)
New Facilities		
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.		29.8
Solar U.S.: Bakersfield II Solar Facility was placed in service in December 2016.		1.9
		31.7
Foreign Exchange		**(1.4)**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease primarily related to lower pass through energy costs at the Calpeco Electric System.		(7.7)
Gas: Increase primarily related to higher pass through gas costs at the EnergyNorth, Peach State, and New England Gas Systems, partially offset by decreased pass through costs at the Midstates Gas System.		23.4
Water: Decrease primarily due to completion of condemnation proceedings on June 22, 2017 of the Mountain Water System in Montana.		(3.6)
Other: Decrease primarily due to lower contracted services.		(3.5)
		8.6
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($573.9 million) on January 1, 2017 and the Luning Solar Facility ($11.7 million) on February 15, 2017.		585.6
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		32.3
Water: Acquisition of Empire's water distribution system on January 1, 2017.		2.0
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		6.1
		626.0
Rate Cases		
Electricity: Implementation of new rates at the Calpeco and Granite State Electric Systems.		10.9
Gas: Implementation of new rates at the New England, Peach State, EnergyNorth, and Midstates Gas Systems.		8.4
Water: Implementation of new rates at the Park Water (Central Basin), Bella Vista, Rio Rico, and Black Mountain Waste Water Systems.		4.0
		23.3
Foreign Exchange		**(10.5)**
Current Period Revenue	**$**	**1,454.5**

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

For the nine months ended September 30, 2017, net earnings attributable to shareholders totaled $133.1 million as compared to $84.6 million during the same period in 2016, an increase of $48.5 million. The increase was due to a $298.8 million increase in earnings from operating facilities, $2.1 million increase in interest, dividend, equity and other income, $1.5 million increase in gains on long lived assets, and $26.2 million increase in net effect of non-controlling interests. These items were partially offset by a $4.3 million decrease on gains from derivative instruments, $0.6 million decrease in foreign exchange gains, $104.1 million increase in depreciation and amortization expenses, $11.8 million increase in administration charges, $8.5 million decrease in other gains, $67.3 million increase in interest expense, $31.6 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*), and $51.9 million increase in acquisition costs as compared to the same period in 2016.

During the nine months ended September 30, 2017, cash provided by operating activities totaled $288.0 million as compared to $166.0 million during the same period in 2016. During the nine months ended September 30, 2017, Adjusted Funds from Operations, a non-GAAP measure, totaled $455.4 million as compared to $260.0 million the same period in 2016, an increase of $195.4 million.

Adjusted EBITDA in the nine months ended September 30, 2017 totaled $650.0 million as compared to $338.6 million during the same period in 2016, an increase of $311.4 million or 92.0%. 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 September 30, 2017 totaled $197.5 million as compared to $91.4 million during the same period in 2016, an increase of $106.1 million or 116.1%. Adjusted EBITDA in the nine months ended September 30, 2017 totaled $650.0 million as compared to $338.6 million during the same period in 2016, an increase of $311.4 million or 92.0%. 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	**Three Months Ended September 30**		**Nine Months Ended September 30**	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Liberty Power Group Operating Profit	**$ 43.1**	$ 44.8	**$ 180.0**	**$ 155.4**
Liberty Utilities Group Operating Profit	**168.2**	57.7	**513.5**	214.8
Administrative Expenses	**(14.4)**	(12.1)	**(45.7)**	(33.9)
Other Income & Expenses	**0.6**	1.0	**2.2**	2.3
Total Algonquin Power & Utilities Adjusted EBITDA	**$ 197.5**	$ 91.4	**$ 650.0**	$ 338.6
Change in Adjusted EBITDA ($)	**$ 106.1**		**$ 311.4**	
Change in Adjusted EBITDA (%)	**116.1%**		**92.0%**	

Change in Adjusted EBITDA	**Three Months Ended September 30, 2017**			
(all dollar amounts in $ millions)	**Power**	**Utilities**	**Corporate**	**Total**
Prior period balances	**$ 44.8**	**$ 57.7**	**$ (11.1)**	**$ 91.4**
Existing Facilities	(7.1)	(6.7)	(0.3)	(14.1)
New Facilities	6.4	112.5	—	118.9
Rate Cases	—	7.3	—	7.3
Foreign Exchange Impact	(1.0)	(2.6)	—	(3.6)
Administrative Expenses	—	—	(2.4)	(2.4)
Total change during the period	**$ (1.7)**	**$ 110.5**	**$ (2.7)**	**$ 106.1**
Current period balances	**$ 43.1**	**$ 168.2**	**$ (13.8)**	**$ 197.5**

Change in Adjusted EBITDA	Nine Months Ended September 30, 2017			
(all dollar amounts in $ millions)	Power	Utilities	Corporate	Total
Prior period balances	**$ 155.4**	**$ 214.8**	**$ (31.6)**	**$ 338.6**
Existing Facilities	(5.9)	(5.6)	—	(11.5)
New Facilities	31.1	284.5	—	315.6
Rate Cases	—	23.3	—	23.3
Foreign Exchange Impact	(0.6)	(3.5)	—	(4.1)
Administration Expenses	—	—	(11.9)	(11.9)
Total change during the period	**$ 24.6**	**$ 298.7**	**$ (11.9)**	**$ 311.4**
Current period balances	**$ 180.0**	**$ 513.5**	**$ (43.5)**	**$ 650.0**

2017 Electricity Generation Performance

(Performance in GW-hrs sold)	Long Term Average Resource	Three Months Ended September 30 2017	Three Months Ended September 30 2016	Long Term Average Resource	Nine Months Ended September 30 2017	Nine Months Ended September 30 2016
Hydro Facilities:						
Maritime Region	**20.7**	**12.3**	28.0	**110.6**	**94.8**	122.2
Quebec Region	**62.3**	**55.3**	50.2	**200.7**	**203.1**	203.5
Ontario Region	**28.5**	**28.1**	26.4	**104.0**	**98.9**	98.2
Western Region	**23.8**	**16.1**	27.4	**52.4**	**49.1**	48.0
	135.3	**111.8**	132.0	**467.7**	**445.9**	471.9
Wind Facilities:						
St. Damase	**16.9**	**14.5**	15.4	**54.2**	**50.3**	54.0
St. Leon	**87.9**	**84.5**	81.7	**308.8**	**305.5**	286.5
Red Lily[1]	**20.4**	**15.7**	16.5	**64.4**	**62.4**	57.2
Morse	**22.6**	**20.9**	20.2	**78.3**	**73.3**	67.1
Sandy Ridge	**29.9**	**20.8**	23.8	**114.7**	**111.3**	104.0
Minonk	**128.7**	**82.8**	87.4	**483.9**	**470.2**	450.9
Senate	**91.7**	**84.8**	102.4	**380.4**	**366.2**	367.7
Shady Oaks	**54.5**	**47.2**	47.9	**255.1**	**256.8**	219.5
Odell[2]	**155.1**	**129.5**	86.5	**593.8**	**562.6**	86.5
Deerfield[3]	**106.3**	**74.5**	—	**312.6**	**285.0**	—
	714.0	**575.2**	481.8	**2,646.2**	**2,543.6**	1,693.4
Solar Facilities:						
Cornwall	**4.8**	**5.4**	5.4	**12.5**	**12.3**	13.7
Bakersfield I	**17.0**	**14.4**	15.9	**43.9**	**39.6**	38.5
Bakersfield II[4]	**8.0**	**6.5**	—	**20.3**	**18.2**	—
	29.8	**26.3**	21.3	**76.7**	**70.1**	52.2
Renewable Energy Performance	**879.1**	**713.3**	635.1	**3,190.6**	**3,059.6**	2,217.5
Thermal Facilities:						
Windsor Locks	**N/A[5]**	**31.0**	45.0	**N/A[5]**	**90.2**	100.1
Sanger	**N/A[5]**	**18.1**	32.0	**N/A[5]**	**52.5**	89.9
		49.1	77.0		**142.7**	190.0
Total Performance		**762.4**	712.1		**3,202.3**	2,407.5

[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 Third Quarter Liberty Power Group Performance

For the three months ended September 30, 2017, the Liberty Power Group generated 762.4 GW-hrs of electricity as compared to 712.1 GW-hrs during the same period of 2016.

For the three months ended September 30, 2017, the hydro facilities generated 111.8 GW-hrs of electricity as compared to 132.0 GW-hrs produced in the same period in 2016, a decrease of 15.3%. Electricity generated represented 82.6% of long-term average resources ("LTAR") as compared to 97.6% during the same period in 2016. The decrease is primarily attributable to reduced hydrology in the Maritime Region.

For the three months ended September 30, 2017, the wind facilities produced 575.2 GW-hrs of electricity as compared to 481.8 GW-hrs produced in the same period in 2016, an increase of 19.4%. 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 partially offset by lower production at the Senate, Minonk and Sandy Ridge Wind Facilities. During the three months ended September 30, 2017, the wind facilities generated electricity equal to 80.6% of LTAR as compared to 89.1% during the same period in 2016. The overall change is primarily attributable to the incremental electricity generated at the Odell and Deerfield Wind Facilities, partially offset by a production decrease at the existing US Wind Facilities.

For the three months ended September 30, 2017, the solar facilities generated 26.3 GW-hrs of electricity as compared to 21.3 GW-hrs of electricity in the same period in 2016, an increase of 23.5%. The increase in production is largely attributable to the new Bakersfield II Solar Facility. Excluding the new facility, the Cornwall and Bakersfield I Solar Facilities had a production decrease of 7.0% as compared to the same period last year.

For the three months ended September 30, 2017, the thermal facilities generated 49.1 GW-hrs of electricity as compared to 77.0 GW-hrs of electricity during the same period in 2016. The decrease is primarily due to a new capacity-based contract at the Sanger Thermal Facility. During the same period, the Windsor Locks Thermal Facility generated 111.8 billion lbs of steam as compared to 103.9 billion lbs of steam during the same period in 2016.

2017 Year-to-Date Liberty Power Performance

For the nine months ended September 30, 2017, the Liberty Power Group generated 3,202.3 GW-hrs of electricity as compared to 2,407.5 GW-hrs during the same period of 2016.

For the nine months ended September 30, 2017, the hydro facilities generated 445.9 GW-hrs of electricity as compared to 471.9 GW-hrs produced in the same period in 2016, a decrease of 5.5%. Electricity generated represented 95.3% of LTAR as compared to 100.9% during the same period in 2016. During the nine months ended September 30, 2017, the Quebec region achieved production above its LTAR, while production in the Maritime, Ontario and Western regions were below their respective LTARs.

For the nine months ended September 30, 2017, the wind facilities produced 2,543.6 GW-hrs of electricity as compared to 1,693.4 GW-hrs produced in the same period in 2016, an increase of 50.2%. During the nine months ended September 30, 2017, the wind facilities generated electricity equal to 96.1% of LTAR as compared to 91.8% during the same period in 2016. The change is primarily attributable to an increase in production across all previously existing U.S. Wind Facilities as well as incremental electricity generated at the Odell and Deerfield Wind Facilities.

For the nine months ended September 30, 2017, the solar facilities generated 70.1 GW-hrs of electricity as compared to 52.2 GW-hrs of electricity produced in the same period in 2016, an increase of 34.3%. The increase in production is primarily attributable to production at the new Bakersfield II Solar Facility which achieved COD on January 11, 2017. Excluding the new facility, production from the Cornwall and Bakersfield I Solar Facilities had a decrease of 0.6% as compared to the same period last year.

For the nine months ended September 30, 2017, the thermal facilities generated 142.7 GW-hrs of electricity as compared to 190.0 GW-hrs of electricity during the same period in 2016. The decrease is primarily due to a new capacity-based contract at the Sanger Thermal Facility. During the same period, the Windsor Locks Thermal Facility generated 422.2 billion lbs of steam as compared to 423.2 billion lbs of steam during the same period in 2016.

2017 Liberty Power Group Operating Results

(all dollar amounts in $ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue[1]				
Hydro	**$ 11.6**	$ 17.9	**$ 44.2**	$ 51.9
Wind	**28.6**	22.8	**117.6**	85.6
Solar	**5.2**	4.7	**11.9**	11.3
Thermal	**11.0**	10.9	**27.6**	27.3
Total Revenue	**$ 56.4**	$ 56.3	**$ 201.3**	$ 176.1
Less:				
Cost of Sales - Energy[2]	**(1.9)**	(1.6)	**(4.6)**	(3.9)
Cost of Sales - Thermal	**(3.4)**	(4.4)	**(13.1)**	(11.1)
Realized loss on hedges[3]	**—**	—	**(0.7)**	(0.9)
Net Energy Sales	**$ 51.1**	$ 50.3	**$ 182.9**	$ 160.2
Renewable Energy Credits ("REC")	**3.3**	3.6	**11.6**	13.9
Other Revenue	**0.2**	0.6	**0.4**	1.9
Total Net Revenue	**$ 54.6**	$ 54.5	**$ 194.9**	$ 176.0
Expenses & Other Income				
Operating expenses	**(22.5)**	(17.4)	**(64.7)**	(52.2)
Interest, dividend, equity and other income	**0.7**	2.5	**2.6**	4.2
HLBV income[4]	**10.3**	5.2	**47.2**	27.4
Divisional Operating Profit[5]	**$ 43.1**	$ 44.8	**$ 180.0**	$ 155.4

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

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

3 See 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 Third Quarter Operating Results

For the three months ended September 30, 2017, the Liberty Power Group generated $43.1 million of operating profit as compared to $44.8 million during the same period in 2016, which represents a decrease of $1.7 million, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Three Months Ended September 30
Prior Period Operating Profit	**$ 44.8**
Existing Facilities	
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO as well as a decline in production in the Maritimes region and lower average market rates in the Western region.	(5.9)
Wind Canada:	(0.1)
Wind U.S.: Decrease primarily due to lower production.	(0.8)
Solar U.S.: Decrease primarily due to lower production.	(0.4)
Thermal: Lower production was offset by lower fuel costs as well as lower operating costs.	1.0
Other: Decrease primarily due to a new capacity based contract at the Sanger Thermal Facility.	(0.9)
	(7.1)
New Facilities	
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.	5.1
Solar U.S.: Bakersfield II was placed in service in December 2016.	1.3
	6.4
Foreign Exchange	**(1.0)**
Current Period Divisional Operating Profit	**$ 43.1**

2017 Year-to-Date Operating Results

For the nine months ended September 30, 2017, the Liberty Power Group generated $180.0 million of operating profit as compared to $155.4 million during the same period in 2016, which represents an increase of $24.6 million or 15.8%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Nine Months Ended September 30	
Prior Period Operating Profit	**$**	**155.4**
Existing Facilities		
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO as well as a decline in production in the Maritime Region.		(7.6)
Wind U.S.: Increase primarily due to higher production and increased HLBV income.		5.6
Solar Canada: Decrease primarily due to lower production.		(0.4)
Solar U.S.: Decrease primarily due to business interruption insurance proceeds received in Q1 2016 in excess of current year operating profit.		(0.7)
Thermal: Decrease primarily attributable to lower production and increased energy costs partially offset by increased rates charged to customers.		(1.0)
Other: Decrease primarily due to a new capacity based contract at the Sanger Thermal Facility.		(1.8)
		(5.9)
New Facilities		
Wind U.S.: Acquisition of Odell and Deerfield Wind facilities.		28.2
Solar U.S.: Bakersfield II was placed in service in December 2016.		2.9
		31.1
Foreign Exchange		**(0.6)**
Current Period Divisional Operating Profit	**$**	**180.0**

LIBERTY UTILITIES GROUP

The Liberty Utilities Group operates rate-regulated utilities that provide distribution services to approximately 758,000 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 September 30			
	2017		2016	
(all dollar amounts in U.S. $ millions)	Assets	Total Connections[1]	Assets	Total Connections[1]
Electricity	$ 2,452.1	264,000	$ 362.9	93,000
Natural Gas	959.9	335,000	816.9	293,000
Water and Wastewater	457.4	159,000	503.0	178,000
Total	$ 3,869.4	758,000	$ 1,682.8	564,000
Accumulated Deferred Income Taxes Liability	$ 693.5		$ 172.4	

[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 264,000 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 159,000 connections located in the states of Arkansas, Arizona, California, Illinois, Missouri, and Texas.

2017 Third Quarter Usage Results

Electric Distribution Systems

	Three Months Ended September 30	
	2017	**2016**
Average Active Electric Connections For The Period		
Residential	**223,700**	80,400
Commercial and industrial	**39,200**	12,400
Total Average Active Electric Connections For The Period	**262,900**	92,800
Customer Usage (GW-hrs)		
Residential	**616.5**	136.8
Commercial and industrial	**953.7**	235.2
Total Customer Usage (GW-hrs)	**1,570.2**	372.0

For the three months ended September 30, 2017, the electric distribution systems' usage totaled 1,570.2 GW-hrs as compared to 372.0 GW-hrs for the same period in 2016, an increase of 1,198.2 GW-hrs or 322.1%. The addition of Empire accounted for 1,208.9 GW-hrs of the increase. The Calpeco Electric System and Granite State Electric System usage totaled 361.3 GW-hrs, a decrease of 10.7 GW-hrs or 2.9%.

Natural Gas Distribution Systems

	Three Months Ended September 30	
	2017	**2016**
Average Active Natural Gas Connections For The Period		
Residential	**283,000**	245,600
Commercial and industrial	**30,900**	26,000
Total Average Active Natural Gas Connections For The Period	**313,900**	271,600
Customer Usage (MMBTU)		
Residential	**1,101,000**	963,000
Commercial and industrial	**1,481,000**	1,276,000
Total Customer Usage (MMBTU)	**2,582,000**	2,239,000

For the three months ended September 30, 2017, usage at the natural gas distribution systems totaled 2,582,000 MMBTU as compared to 2,239,000 MMBTU during the same period in 2016, an increase of 343,000 MMBTU or 15.3%. The addition of Empire accounted for 172,000 MMBTU of the increase.

Water and Wastewater Distribution Systems

	Three Months Ended September 30	
	2017	**2016**
Average Active Connections For The Period		
Wastewater connections	**41,000**	40,400
Water distribution connections	**111,700**	131,200
Total Average Active Connections For The Period	**152,700**	171,600
Gallons Provided		
Wastewater treated (millions of gallons)	**547**	529
Water sold (millions of gallons)	**4,895**	6,102
Total Gallons Provided	**5,442**	6,631

During the three months ended September 30, 2017, the water and wastewater distribution systems provided approximately 4,895 million gallons of water to its customers and treated approximately 547 million gallons of wastewater as compared to 6,102 million gallons of water provided and 529 million gallons of wastewater treated during the same period in 2016. The decrease in water connections and water sold during the period is primarily due to the completion of condemnation proceedings at the Mountain Water System in Montana on June 22, 2017.

2017 Third Quarter Operating Results

	Three Months Ended September 30			
	2017 U.S. $ (millions)	**2016 U.S. $ (millions)**	**2017 Cdn $ (millions)**	**2016 Cdn $ (millions)**
Revenue				
Utility electricity sales and distribution	**$ 217.4**	$ 41.6	**$ 272.6**	$ 54.2
Less: cost of sales – electricity	**(65.2)**	(21.7)	**(81.9)**	(28.4)
Net Utility Sales - electricity	**152.2**	19.9	**190.7**	25.8
Utility natural gas sales and distribution	**42.8**	33.9	**53.6**	44.2
Less: cost of sales – natural gas	**(10.6)**	(7.1)	**(13.3)**	(9.3)
Net Utility Sales - natural gas	**32.2**	26.8	**40.3**	34.9
Utility water distribution & wastewater treatment sales and distribution	**38.2**	39.1	**48.0**	51.0
Less: cost of sales – water	**(2.7)**	(2.7)	**(3.3)**	(3.5)
Net Utility Sales - water distribution & wastewater treatment	**35.5**	36.4	**44.7**	47.5
Gas transportation	**4.3**	3.6	**5.4**	4.7
Other revenue	**3.0**	4.8	**3.7**	6.5
Net Utility Sales	**$ 227.2**	$ 91.5	**$ 284.8**	$ 119.4
Operating expenses	**(95.6)**	(48.3)	**(119.8)**	(63.0)
Other income	**0.9**	1.0	**1.2**	1.3
HLBV	**1.6**	—	**2.0**	—
Divisional Operating Profit[1]	**$ 134.1**	$ 44.2	**$ 168.2**	$ 57.7

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

For the three months ended September 30, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $134.1 million as compared to U.S. $44.2 million for the comparable period in the prior year. Measured in Canadian dollars, the Group's operating profit was $168.2 million as compared to $57.7 million during the same period in 2016, which represents an increase of $110.5 million or 192%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Three Months Ended September 30
Prior Period Operating Profit	**$**	**57.7**
Existing Facilities		
Electricity: Decrease primarily due to lower volumes at the Granite State Electric System as a result of fewer cooling degree days as compared to the same period in the prior year.		(0.9)
Gas: Decrease primarily due to higher operating costs at the EnergyNorth and Peach State Gas Systems.		(0.7)
Water: Decrease primarily due to completion of condemnation proceedings on June 22, 2017 of the Mountain Water System in Montana.		(1.6)
Other: Decrease primarily due lower revenues for contracted services.		(3.5)
		(6.7)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system on January 1, 2017 ($104.0) and the Luning Solar Facility on February 15, 2017 ($5.4).		109.4
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		1.2
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.3
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		1.6
		112.5
Rate Cases		
Electricity: Implementation of new rates at the Calpeco and Granite State Electric Systems.		3.7
Gas: Implementation of new rates at the EnergyNorth, New England, and Peach State Gas Systems.		1.8
Water: Implementation of new rates at the Park Water and the Rio Rico Water Systems.		1.8
		7.3
Foreign Exchange		**(2.6)**
Current Period Divisional Operating Profit	**$**	**168.2**

2017 Year-to-Date Usage Results

Electric Distribution Systems

	Nine Months Ended September 30	
	2017	**2016**
Average Active Electric Connections For The Period		
Residential	**223,400**	80,300
Commercial and industrial	**39,100**	12,400
Total Average Active Electric Connections For The Period	**262,500**	92,700
Customer Usage (GW-hrs)		
Residential	**1,748.4**	424.5
Commercial and industrial	**2,640.8**	670.2
Total Customer Usage (GW-hrs)	**4,389.2**	1,094.7

For the nine months ended September 30, 2017, the electric distribution systems' usage totaled 4,389.2 GW-hrs as compared to 1,094.7 GW-hrs for the same period in 2016, an increase of 3,294.5 GW-hrs. The addition of Empire accounted for 3,294.7 GW-hrs of the increase. Customer usage at the Calpeco Electric System was 15.8 GW-hrs higher and was offset by 16.0 GW-hrs of lower usage at the Granite State Electric System due to lower cooling degree days experienced in the region.

Natural Gas Distribution Systems

	Nine Months Ended September 30	
	2017	**2016**
Average Active Natural Gas Connections For The Period		
Residential	**287,100**	249,300
Commercial and industrial	**31,600**	26,500
Total Average Active Natural Gas Connections For The Period	**318,700**	275,800
Customer Usage (MMBTU)		
Residential	**12,424,000**	11,610,000
Commercial and industrial	**8,390,000**	7,915,000
Total Customer Usage (MMBTU)	**20,814,000**	19,525,000

For the nine months ended September 30, 2017, usage at the natural gas distribution systems totaled 20,814,000 MMBTU as compared to 19,525,000 MMBTU during the same period in 2016, an increase of 1,289,000 MMBTU or 6.6%. The addition of Empire accounted for 1,928,000 MMBTU of the increase. The Midstates 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

	Nine Months Ended September 30	
	2017	**2016**
Average Active Connections For The Period		
Wastewater connections	**40,900**	41,400
Water distribution connections	**124,500**	132,500
Total Average Active Connections For The Period	**165,400**	173,900
Gallons Provided		
Wastewater treated (millions of gallons)	**1,670**	1,688
Water sold (millions of gallons)	**12,996**	13,823
Total Gallons Provided	**14,666**	15,511

During the nine months ended September 30, 2017, the water and wastewater distribution systems provided approximately 12,996 million gallons of water to its customers and treated approximately 1,670 million gallons of wastewater as compared to 13,823 million gallons of water and 1,688 million gallons of wastewater during the same period in 2016. The decrease in water sold during the period is primarily due to the completion of condemnation proceedings at the Mountain Water System in Montana on June 22, 2017 partially offset by the addition of Empire water distribution system which accounted for 239 million gallons in the period.

2017 Year-to-Date Operating Results

	Nine Months Ended September 30			
	2017 U.S. $ (millions)	2016 U.S. $ (millions)	2017 Can $ (millions)	2016 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 576.5**	$ 124.8	**$ 751.4**	$ 165.5
Less: cost of sales – electricity	**(170.9)**	(69.4)	**(222.6)**	(92.3)
Net Utility Sales - electricity	**405.6**	55.4	**528.8**	73.2
Utility natural gas sales and distribution	**236.2**	191.7	**310.7**	257.3
Less: cost of sales – natural gas	**(88.6)**	(65.2)	**(116.8)**	(88.9)
Net Utility Sales - natural gas	**147.6**	126.5	**193.9**	168.4
Utility water distribution & wastewater treatment sales and distribution	**108.6**	105.7	**141.8**	139.4
Less: cost of sales – water	**(7.1)**	(7.0)	**(9.2)**	(9.2)
Net Utility Sales - water distribution & wastewater treatment	**101.5**	98.7	**132.6**	130.2
Gas transportation	**21.6**	17.3	**28.4**	23.6
Other revenue	**6.7**	6.0	**8.7**	8.0
Net Utility Sales	**$ 683.0**	$ 303.9	**$ 892.4**	$ 403.4
Operating expenses	**(297.1)**	(145.5)	**(388.9)**	(192.5)
Other income	**2.8**	2.9	**3.7**	3.9
HLBV	**4.8**	—	**6.3**	—
Divisional Operating Profit[1]	**$ 393.5**	$ 161.3	**$ 513.5**	$ 214.8

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

For the nine months ended September 30, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $393.5 million as compared to U.S. $161.3 million for the comparable period in the prior year. Measured in Canadian dollars, the group's operating profit was $513.5 million as compared to $214.8 million during the same period in 2016, which represents an increase of $298.7 million or 139%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Nine Months Ended September 30
Prior Period Operating Profit	**$**	**214.8**
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.		(0.4)
Gas: Increase primarily due to increased consumption at the EnergyNorth Gas System partially offset by decreased consumption at Peach State and Midstates Gas Systems.		1.5
Water: Decrease primarily due to completion of condemnation proceedings on June 22, 2017 of the Mountain Water System in Montana.		(3.1)
Other: Decrease primarily due lower revenues for contracted services.		(3.6)
		(5.6)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system on January 1, 2017 ($255.5), and the Luning Solar Facility on February 15, 2017 ($16.6).		272.1
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		7.6
Water: Acquisition of Empire's water distribution system on January 1, 2017.		1.0
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		3.8
		284.5
Rate Cases		
Electricity: Implementation of new rates at the Calpeco Electric and the Granite State Electric Systems.		10.9
Gas: Implementation of new rates at the New England, Peach State, EnergyNorth, and Midstates Gas Systems.		8.4
Water: Implementation of new rates at the Park Water, Bella Vista, Rio Rico Water, and Black Mountain Waste Water System.		4.0
		23.3
Foreign Exchange		**(3.5)**
Current Period Divisional Operating Profit	**$**	**513.5**

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				
Oklahoma Electricity System	Oklahoma	General Rate Case	$3.0	In lieu of authorizing the proposed rate increase the Commission ordered an immediate increase of $1.0 million to capture the return on and of major capital investments related to plant upgrades and authorized Liberty Utilities to return in 2018 to seek the remaining proposed increases.
Pending Rate Cases				
EnergyNorth Gas System	New Hampshire	General Rate Case	$19.9	On April 28, 2017, filed an application seeking a rate 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 an application (test year December 31, 2016) seeking a rate increase of U.S. $5.1 million. New rates are expected to be effective Q3 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 placed into service in the fourth quarter of 2018.
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 rate 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 October, 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 Q1 2018.
Missouri Gas System	Missouri	General Rate Case	$7.5	On September 29, 2017, filed an application seeking a U.S. $7.5 million rate increase for test year ending June 30, 2017 with proforma adjustments through to March 31, 2018. New rates are expected to be effective in Q3 2018.
Georgia Gas System	Georgia	Georgia Rate Adjustment Mechanism (GRAM)	$1.4	On September 29, 2017, filed a 2018 GRAM application seeking a U.S. $1.4 million rate increase for Test Year ending August 30, 2018. New rates are expected to be effective February 1, 2018.

Completed Rate Cases

On December 21, 2016, Empire filed an application with the Oklahoma Corporation Commission ("OCC") requesting a rate increase of U.S. $3.0 million based on historical test year ending June 30, 2016 with known and measurable adjustments through December 31, 2016. On June 9, 2017, the ALJ issued a report and recommendation to the Commission, which includes a revenue requirement of U.S. $2.6M based on a 9.5% return on equity ("ROE") and 49.7% equity. On August 17, 2017, in lieu of authorizing the proposed rate increase the Commission ordered an immediate increase of $1.0 million to capture the return on and of major capital investments related to plant upgrades and authorized Liberty Utilities to return in 2018 to seek the remaining proposed increases.

CORPORATE DEVELOPMENT ACTIVITIES

The Company's Corporate Development group is focused on developing and contracting projects, and transitioning recently completed projects to the operations group. The group has successfully developed 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, signed PPAs with credit-worthy counterparties, and satisfaction of 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	168 - 187	2017	10	146
Total Projects in Construction		**150**	**$ 458 - $ 512**			**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	25 - 31	2018		28
Total Projects in Development		**211**	**$ 400 - $ 451**			**907**
Total in Construction and Development		**361**	**$ 858 - $ 963**			**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 total costs to complete the project are estimated at approximately $290.0 million to $325.0 million. Construction over the spring and summer months has focused primarily on the project's mainland and island docks which are now completed and in regular use for project construction activities.

Manufacturing and delivery of major equipment (turbines, main power transformer) continues on schedule, and are nearing completion. Public road strengthening and access road construction are in progress. Major construction activities are underway, with turbine deliveries targeted to start in November 2017. Subject to receipt of ongoing construction-related permitting, 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 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.

The project substation was completed and backfed in August, and the collection system was energized shortly thereafter. Module installation is 90% complete, and inverter installation is 97% complete. Mechanical completion and placed in service activities for two of the four project sites were achieved in September. Commercial operation is expected by the end of 2017.

The total costs to complete the project are estimated at approximately U.S. $135.0 million to U.S. $150.0 million. Approximately 40% of the permanent project financing will come from Tax Equity investors. Initial funding of U.S. $12.5 million and U.S. $5.0 million was received on September 19, 2017 and October 31, 2017, respectively.

APUC: CORPORATE AND OTHER EXPENSES

(all dollar amounts in $ millions)	Three Months Ended September 30 2017	Three Months Ended September 30 2016	Nine Months Ended September 30 2017	Nine Months Ended September 30 2016
Corporate and other expenses:				
Administrative expenses	**$ 14.4**	$ 12.1	**$ 45.7**	$ 33.9
Loss (gain) on foreign exchange	**2.6**	(3.4)	**(1.2)**	(1.8)
Interest expense on convertible debentures and acquisition facility due to the acquisition of Empire	**—**	17.0	**17.6**	39.4
Interest expense	**45.6**	17.8	**142.6**	53.5
Interest, dividend, equity, and other income[1]	**(0.6)**	(0.7)	**(2.2)**	(2.3)
Other gains[2]	**0.8**	(2.2)	**(4.1)**	(11.0)
Acquisition-related costs	**1.1**	2.1	**61.5**	9.6
Loss (gain) on derivative financial instruments	**—**	(4.4)	**1.4**	(2.9)
Income tax expense	**14.8**	1.8	**57.2**	25.6

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 Third Quarter Corporate and Other Expenses

During the three months ended September 30, 2017, administrative expenses totaled $14.4 million as compared to $12.1 million in the same period in 2016. The $2.3 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 September 30, 2017, interest expense totaled $45.6 million as compared to $17.8 million in the same period in 2016. The increase is primarily attributable to assumed and incremental debt related to the Empire acquisition, 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 September 30, 2017, other losses were $0.8 million as compared to gains of $2.2 million in the same period in 2016. The prior period gains were primarily due to gains on marketable securities and insurance recoveries.

For the three months ended September 30, 2017, acquisition-related costs totaled $1.1 million as compared to $2.1 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 September 30, 2017, loss on derivative financial instruments totaled $nil as compared to a gain of $4.4 million in the same period in 2016. The prior period gain was primarily driven by mark-to-market gains on foreign currency hedges.

For the three months ended September 30, 2017, income tax expense of $14.8 million was recorded as compared to income tax expense of $1.8 million during the same period in 2016. The increase in income tax expense is primarily due to the acquisition of Empire.

2017 Year-to-Date Corporate and Other Expenses

During the nine months ended September 30, 2017, administrative expenses totaled $45.7 million as compared to $33.9 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 nine months ended September 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 nine months ended September 30, 2017, interest expense totaled $142.6 million as compared to $53.5 million in the same period in 2016. The increase in interest expense for the period is primarily attributable to assumed and incremental debt related to the Empire acquisition, and new debt raised at Liberty Power and Liberty Utilities. (S*ee Credit Facilities & Debt and Unaudited Interim Consolidated Financial Statements note 7.*)

For the nine months ended September 30, 2017, other gains totaled $4.1 million as compared to a gain of $11.0 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 were canceled by the developer.

For the nine months ended September 30, 2017, acquisition related costs totaled $61.5 million as compared to $9.6 million in the same period in 2016. The increase is primarily attributable to the Empire acquisition.

For the nine months ended September 30, 2017, the loss on derivative financial instruments totaled $1.4 million as compared to a gain of $2.9 million in the same period in 2016.

An income tax expense of $57.2 million was recorded in the nine months ended September 30, 2017 as compared to an income tax expense of $25.6 million during the same period in 2016. The increase in income tax expense for the nine months ended September 30, 2017 is primarily due 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.

	Three Months Ended September 30		Nine Months Ended September 30	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Net earnings attributable to shareholders	**$ 59.4**	$ 17.7	**$ 133.1**	$ 84.6
Add (deduct):				
Net earnings attributable to the non-controlling interest, exclusive of HLBV	**0.6**	5.2	**2.4**	8.3
Income tax expense	**14.8**	1.8	**57.2**	25.6
Interest expense on convertible debentures and acquisition financing	**—**	17.0	**17.6**	39.4
Interest expense on long-term debt and others	**45.6**	17.8	**142.6**	53.5
Other gains	**—**	(2.3)	**(0.1)**	(8.6)
Loss (gain) on long-lived assets, net	**0.8**	0.2	**(4.0)**	(2.5)
Acquisition-related costs	**1.1**	2.1	**61.5**	9.6
Costs related to tax equity financing	**1.2**	—	**1.8**	—
Loss (gain) on derivative financial instruments	**—**	(4.4)	**1.4**	(2.9)
Realized gain on energy derivative contracts	**—**	—	**(0.7)**	(0.9)
Loss (gain) on foreign exchange	**2.6**	(3.4)	**(1.2)**	(1.8)
Depreciation and amortization	**71.4**	39.7	**238.4**	134.3
Adjusted EBITDA	**$ 197.5**	$ 91.4	**$ 650.0**	$ 338.6

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 nine months ended September 30, 2017 amounted to $12.3 million and $53.5 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:

	Three Months Ended September 30		Nine Months Ended September 30	
(all dollar amounts in $ millions)	2017	2016	2017	2016
Net earnings attributable to shareholders	**$ 59.4**	$ 17.7	**$ 133.1**	$ 84.6
Add (deduct):				
Loss (gain) on derivative financial instruments	**—**	(4.4)	**1.4**	(2.9)
Realized gain on derivative financial instruments	**—**	—	**(0.7)**	(0.9)
Loss (gain) on long-lived assets, net	**0.8**	0.2	**(4.0)**	(2.5)
Loss (gain) on foreign exchange	**2.6**	(3.4)	**(1.2)**	(1.8)
Interest expense on convertible debentures and acquisition financing	**—**	17.0	**17.6**	39.4
Acquisition-related costs	**1.1**	2.1	**61.5**	9.6
Costs related to tax equity financing	**1.2**	—	**1.8**	—
Adjustment for taxes related to above	**(0.2)**	(2.7)	**(3.3)**	(11.5)
Adjusted Net Earnings	**$ 64.9**	$ 26.6	**$ 206.2**	$ 114.0
Adjusted Net Earnings per share[1]	**$ 0.16**	$ 0.09	**$ 0.53**	$ 0.40

[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 September 30, 2017, Adjusted Net Earnings totaled $64.9 million as compared to $26.6 million, an increase of $38.3 million as compared to the same period in 2016. The increase in Adjusted Net Earnings for the three months ended September 30, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and interest expense as compared to 2016.

For the nine months ended September 30, 2017, Adjusted Net Earnings totaled $206.2 million as compared to $114.0 million, an increase of $92.2 million as compared to the same period in 2016. The increase in Adjusted Net Earnings for the nine months ended September 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 September 30 2017	Three Months Ended September 30 2016	Nine Months Ended September 30 2017	Nine Months Ended September 30 2016
Cash flows from operating activities	**$ 119.1**	$ 22.6	**$ 288.0**	$ 166.0
Add (deduct):				
Changes in non-cash operating items	**6.8**	18.7	**86.0**	43.0
Production based cash contributions from non-controlling interests	**—**	0.6	**10.6**	10.6
Interest expense on convertible debentures and acquisition financing fees[1]	**—**	17.0	**9.3**	39.4
Acquisition-related costs	**1.1**	2.1	**61.5**	9.6
Cash generated from sale of long-lived assets	**—**	—	**—**	(8.6)
Adjusted Funds from Operations	**$ 127.0**	$ 61.0	**$ 455.4**	$ 260.0

[1] Exclusive of deferred financing fees of $8.3 million.

For the nine months ended September 30, 2017, Adjusted Funds from Operations totaled $455.4 million as compared to Adjusted Funds from Operations of $260.0 million, an increase of $195.4 million as compared to the same period in 2016.

SUMMARY OF CAPITAL EXPENDITURES[1]

(all dollar amounts in $ millions)	Three Months Ended September 30 2017	Three Months Ended September 30 2016	Nine Months Ended September 30 2017	Nine Months Ended September 30 2016
Liberty Power Group:				
Maintenance	**$ 3.8**	$ 8.2	**$ 14.1**	$ 29.5
Investment in Growth Capital Projects[1]	**109.6**	554.6	**600.8**	603.0
	$ 113.4	$ 562.8	**$ 614.9**	$ 632.5
Liberty Utilities Group:				
Rate Base Maintenance	**$ 50.9**	$ 23.2	**$ 163.7**	$ 75.4
Rate Base Acquisition	**—**	—	**2,764.9**	345.3
Rate Base Growth	**68.9**	39.6	**238.3**	65.9
	119.8	62.8	**$ 3,166.9**	$ 486.6
Total Capital Expenditures	**$ 233.2**	$ 625.6	**$ 3,781.8**	$ 1,119.1

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

2017 Third Quarter Capital Expenditures

During the three months ended September 30, 2017, the Liberty Power Group incurred capital expenditures of $113.4 million as compared to $562.8 million during the same period in 2016. The capital expenditures include the construction of the Great Bay Solar, Amherst Wind, and Tinker Transmission Projects, and ongoing maintenance at operating sites. Capital expenditures in the same quarter last year included the acquisition of the Odell Wind Facility.

During the three months ended September 30, 2017, the Liberty Utilities Group incurred capital expenditures of $119.8 million as compared to $62.8 million during the same period in 2016. The capital expenditures primarily include reliability enhancements, improvements and replenishment opportunities at the utility systems served.

2017 Year-to-Date Capital Expenditures

During the nine months ended September 30, 2017, the Liberty Power Group incurred capital expenditures of $614.9 million as compared to $632.5 million during the same period in 2016. The capital expenditures include the acquisition of the remaining outstanding interest in the Deerfield Wind Facility and construction of the Great Bay Solar, Bakersfield II Solar, and the Tinker Transmission Projects.

During the nine months ended September 30, 2017, the Liberty Utilities Group incurred $3.2 billion in capital expenditures as compared to $486.6 million during the same period in 2016. The increase in capital expenditures are primarily due to the acquisition of Empire in January 2017 (U.S. $2.4 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 at the utility systems served.

2017 Capital Investments

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

Expected 2017 capital investment ranges are as follows:

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

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

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving credit and letter of credit facilities available for the 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 September 30, 2017:

	As at September 30, 2017				As at Dec 31, 2016
(all dollar amounts in $ millions)	**Corporate**	**Liberty Power**	**Liberty Utilities**	**Total**	**Total**
Committed facilities	$ 165.0	$ 587.4	$ 499.2	**$ 1,251.6**	$ 773.8
Funds drawn on facilities	(115.0)	(391.2)	(147.3)	**(653.5)**	(242.9)
Letters of credit issued	(11.4)	(89.4)	(28.1)	**(128.9)**	(234.9)
Liquidity available under the facilities	**38.6**	**106.8**	**323.8**	**469.2**	296.0
Cash on hand				**76.5**	110.4
Total Liquidity and Capital Reserves	**$ 38.6**	**$ 106.8**	**$ 323.8**	**$ 545.7**	$ 406.4

As at September 30, 2017, the Company's $165.0 million senior unsecured bilateral revolving credit facility (the "Corporate Credit Facility") had drawn a total of $115.0 million and had $11.4 million of outstanding letters of credit. During the quarter the facility was increased from $65.0 million to $165.0 million and the maturity was extended to November 19, 2018.

As at September 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 $87.4 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 September 30, 2017, the Liberty Power Group had drawn a total of $391.2 million on the facilities and issued $89.4 million in letters of credit. Subsequent to quarter, on October 6, 2017, the Liberty Power Group's syndicated revolving credit facility was increased to U.S. $500.0 million and the maturity was extended to October 6, 2022. The senior unsecured bilateral revolving credit facilities drawn balance of $118.7 million at September 30, 2017 was fully repaid on October 6, 2017.

As at September 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 the Empire District Company ("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). As at September 30, 2017 the Liberty Utilities Group had drawn a total of $147.3 million and had $28.1 million of outstanding letters of credit.

Long Term Debt

As at September 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 September 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]	**$ 4,392.9**	$ 521.7	$ 863.4	$ 686.1	$ 2,321.7
Convertible debentures	**2.6**	—	—	—	2.6
Advances in aid of construction	**76.8**	1.5	—	—	75.3
Interest on long-term debt obligations	**2,069.3**	199.3	313.4	251.4	1,305.2
Purchase obligations	**404.1**	404.1	—	—	—
Environmental obligations	**92.1**	3.1	23.1	4.9	61.0
Derivative financial instruments:					
Cross currency swap	**71.4**	4.2	7.9	63.8	(4.5)
Interest rate swap	**10.5**	10.5	—	—	—
Commodity contracts	**2.1**	1.5	0.6	—	—
Purchased power	**516.4**	62.8	97.0	100.0	256.6
Gas delivery, service and supply agreements	**387.7**	97.6	126.7	64.5	98.9
Service agreements	**678.6**	45.4	93.5	94.9	444.8
Capital projects	**24.3**	24.3	—	—	—
Operating leases	**275.5**	10.1	18.5	17.7	229.2
Other obligations	**177.9**	35.5	0.2	0.2	142.0
Total Obligations	**$ 9,182.2**	**$ 1,421.6**	**$ 1,544.3**	**$ 1,283.5**	**$ 4,932.8**

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

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange (“TSX”) and the New York Stock Exchange ("NYSE") under the trading symbol "AQN". As at September 30, 2017, APUC had 387,036,183 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.

On November 10, 2017, APUC announced that it closed a bought deal offering announced on November 1, 2017, including the exercise in full of the underwriters' over-allotment option. As a result a total of 43,470,000 common shares of APUC were sold at a price of $13.25 per share for gross proceeds of approximately $576.0 million.

Net proceeds of the offering are expected to be used, in part, to finance APUC's acquisition of a 25% ownership stake in Atlantica from Abengoa and for general corporate purposes.

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 November 13, 2017, $2.5 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 September 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 September 30, 2017, 92,755,569 common shares representing approximately 24% of total common shares outstanding had been registered with the Reinvestment Plan. During the quarter ended September 30, 2017, 1,194,340 common shares were issued under the Reinvestment Plan, and subsequent to quarter, on October 13, 2017, an additional 1,065,834 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 nine months ended September 30, 2017, APUC recorded $7.2 million in total share-based compensation expense as compared to $4.1 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 September 30, 2017, total unrecognized compensation costs related to non-vested options and share unit awards were $3.6 million and $8.2 million, respectively, and are expected to be recognized over a period of 1.55 and 2.03 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 nine months ended September 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 September 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 nine months ended September 30, 2017, the Company granted (including dividends and performance adjustments) 778,585 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 21,800 PSUs were forfeited.

As at September 30, 2017, a total of 970,336 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 nine months ended September 30, 2017, the Company issued 52,416 DSUs (including DSUs in lieu of dividends) to the directors of the Company.

As at September 30, 2017, a total of 277,079 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 nine months ended September 30, 2017, the Company issued 232,093 common shares to employees under the ESPP.

As at September 30, 2017, a total of 728,123 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. The Energy Services Business sold electricity to Maine Public Service Company and Bangor Hydro, both of which are subsidiaries of Emera. The portion considered related party transactions during the three and nine months ended September 30, 2017 amounts to U.S. $nil and $4.4 million as compared to U.S. $3.1 million and $8.0 million during the same period in 2016. The Liberty Utilities Group purchased natural gas from Emera for its gas utility customers. The portion considered related party transactions during the three and nine months ended September 30, 2017 amounts to U.S. $nil and $1.0 million as compared to U.S. $0.5 million and $2.8 million during the same period in 2016. 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 fourth quarter. 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. $1.7 million included in accruals for the nine months ended September 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 nine months ended September 30, 2017, the Company charged its equity-method investees $0.7 million and $1.5 million as compared to $0.9 million and $2.5 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 $115.0 million outstanding as at September 30, 2017. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.2 million annually;
- The Liberty Power Group revolving credit facility is subject to a variable interest rate and had $272.5 million outstanding as at September 30, 2017. A 100 basis point change in the variable rate charged would impact interest expense by $2.7 million annually;
- The Liberty Power Group bilateral revolving credit facility is subject to a variable interest rate and had $118.7 million outstanding as at September 30, 2017. A 100 basis point change in the variable rate charged would impact interest expense by $1.2 million annually;
- The Liberty Utilities Group revolving credit facility is subject to a variable interest rate and had $147.3 million outstanding as at September 30, 2017. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.47 million;
- The Liberty Utilities Group commercial paper program is subject to a variable interest rate and had no amounts outstanding as at September 30, 2017. A 100 basis point change in the variable rate charged would not impact interest expense; and
- The Corporate term credit facility is subject to a variable interest rate and had $168.5 million (U.S. $135.0 million) outstanding as at September 30, 2017. A 100 basis point change in the variable rate charged would impact interest expense by $1.7 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.

See further discussion of the litigation claims made by or against APUC or its subsidiaries in *Regulatory and Contractual Risk*.

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 September 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 condemnation case initiated by the Town of Apple Valley is currently proceeding in discovery. A ballot measure (Measure V) initiated by citizens and supported by Liberty Apple Valley passed in the November 2016 election. Measure V requires the Town to put to a public vote any debt over $10.0 million to be issued related to an enterprise fund activity. In response, on March 9, 2017, the Apple Valley Town Council voted to call a special election on June 6, 2017 to approve a ballot measure authorizing the Town to incur U.S. $150.0 million in bonds for the purpose of funding an attempted taking of the Liberty Apple Valley water system. On June 6, 2017, the measure (Measure F) passed by vote of the Town citizens. Resolution of the condemnation proceedings is expected to take two to three years. At a scheduling conference in July 2017, the Court set a briefing schedule for the related CEQA lawsuit initiated by Liberty Apple Valley with a hearing scheduled for December, 2017. The CEQA decision is expected to be issued within 90 days of the hearing. It is expected that the first phase of the condemnation trial will be set to commence during the second half of 2018, after resolution of the CEQA matter.

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 September 30, 2017:

(all dollar amounts in $ millions except per share information)	4th Quarter 2016	1st Quarter 2017	2nd Quarter 2017	3rd Quarter 2017
Revenue	$ 310.2	$ 557.9	$ 453.2	$ 443.3
Net earnings attributable to shareholders	46.3	26.0	47.7	59.4
Net earnings per share	0.16	0.07	0.12	0.15
Adjusted Net Earnings	51.4	88.1	53.3	64.9
Adjusted Net Earnings per share	0.18	0.25	0.13	0.16
Adjusted EBITDA	138.3	254.8	197.6	197.5
Total assets	8,249.5	10,880.7	10,528.6	10,306.7
Long term debt[1]	4,272.0	4,773.6	4,418.0	4,435.1
Dividend declared per common share	$ 0.14	$ 0.15	$ 0.16	$ 0.15
	4th Quarter 2015	**1st Quarter 2016**	**2nd Quarter 2016**	**3rd Quarter 2016**
Revenue	$ 260.3	$ 341.7	$ 222.8	$ 221.3
Net earnings attributable to shareholders	38.0	42.0	24.8	17.7
Net earnings per share	0.14	0.15	0.08	0.06
Adjusted Net Earnings	39.7	56.1	30.9	26.6
Adjusted Net Earnings per share	0.15	0.21	0.11	0.09
Adjusted EBITDA	109.6	147.9	99.2	91.4
Total assets	4,991.7	5,615.5	5,555.0	6,020.8
Long term debt[1]	1,486.8	2,214.5	2,199.9	2,380.8
Dividend declared per common share	$ 0.13	$ 0.13	$ 0.14	$ 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 $221.3 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 $17.7 million and net earnings of $59.4 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 September 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 September 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 nine months ended September 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 nine months ended September 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)

	September 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 76,462	$ 110,417
Accounts receivable, net (note 4)	225,946	189,658
Fuel and natural gas in storage	56,676	21,625
Supplies and consumables inventory	51,886	15,568
Regulatory assets (note 5)	74,148	48,440
Prepaid expenses	35,318	26,562
Derivative instruments (note 21)	22,786	76,631
Other assets (note 6)	11,824	2,951
	555,046	491,852
Property, plant and equipment, net	7,790,421	4,889,946
Intangible assets, net	60,139	64,989
Goodwill (note 3(c))	1,173,013	306,641
Regulatory assets (note 5)	450,997	243,524
Derivative instruments (note 21)	76,421	74,553
Long-term investments (note 6)	110,405	105,433
Deferred income taxes (note 16)	59,970	30,005
Restricted cash	16,059	2,026,183
Other assets	14,266	16,334
	$10,306,737	$ 8,249,460

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	September 30, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 70,804	$ 90,592
Accrued liabilities	333,330	308,318
Dividends payable (note 13)	56,537	38,973
Regulatory liabilities (note 5)	53,946	47,769
Long-term debt (note 7)	8,426	10,075
Other long-term liabilities and deferred credits (note 9)	44,842	43,157
Derivative instruments (note 21)	16,233	4,178
Other liabilities	6,009	3,487
	590,127	546,549
Long-term debt (note 7)	4,424,023	3,903,340
Convertible debentures (note 10)	2,603	358,619
Regulatory liabilities (note 5)	216,727	134,965
Deferred income taxes (note 16)	876,146	288,139
Derivative instruments (note 21)	67,726	104,647
Pension and other post-employment benefits obligation (note 8)	225,058	147,845
Other long-term liabilities (note 9)	271,192	232,449
Preferred shares, Series C	17,449	17,552
	6,100,924	5,187,556
Redeemable non-controlling interest	60,790	29,434
Equity:		
Preferred shares	213,805	213,805
Common shares (note 11(a))	3,138,541	1,972,203
Additional paid-in capital	39,746	38,652
Deficit	(611,141)	(556,024)
Accumulated other comprehensive income (note 12)	48,025	254,927
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	2,828,976	1,923,563
Non-controlling interests (notes 3(a), 3(e) and 6(a))	725,920	562,358
Total equity	3,554,896	2,485,921
Commitments and contingencies (note 19)		
Subsequent events (notes 7 and 22)		
	$10,306,737	$ 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 September 30		Nine Months Ended September 30	
	2017	2016	2017	2016
Revenue				
Regulated electricity distribution	$ 272,616	$ 54,245	$ 751,409	$ 165,548
Regulated gas distribution	59,438	49,372	340,518	282,307
Regulated water reclamation and distribution	47,952	50,978	141,795	139,385
Non-regulated energy sales	56,505	56,390	201,313	176,149
Other revenue	6,805	10,292	19,421	22,395
	443,316	221,277	1,454,456	785,784
Expenses				
Operating expenses	142,279	80,349	453,639	244,731
Regulated electricity purchased	81,874	28,352	222,587	92,284
Regulated gas purchased	13,276	9,291	116,806	88,880
Regulated water purchased	3,333	3,504	9,232	9,228
Non-regulated energy purchased	5,379	6,018	17,679	15,042
Administrative expenses	14,438	12,071	45,746	33,864
Depreciation and amortization	71,407	39,733	238,422	134,267
Loss (gain) on foreign exchange	2,643	(3,355)	(1,193)	(1,782)
	334,629	175,963	1,102,918	616,514
Operating income	108,687	45,314	351,538	169,270
Interest expense on convertible debentures and amortization of acquisition financing (notes 7(b) and 10)	—	16,994	17,638	39,386
Interest expense on long-term debt and others	45,613	17,773	142,580	53,511
Interest, dividend, equity and other income	(2,455)	(1,505)	(8,514)	(6,435)
Other gains	—	(2,343)	(78)	(8,555)
Acquisition-related costs (note 3)	1,050	2,148	61,527	9,638
Loss (gain) on long-lived assets, net (note 19(a))	816	150	(4,007)	(2,459)
Loss (gain) on derivative financial instruments (note 21(b)(iv))	(14)	(4,419)	1,356	(2,902)
	45,010	28,798	210,502	82,184
Earnings before income taxes	63,677	16,516	141,036	87,086
Income tax expense (note 16)				
Current	3,163	2,532	10,731	7,899
Deferred	11,620	(737)	46,470	17,732
	14,783	1,795	57,201	25,631
Net earnings	48,894	14,721	83,835	61,455
Net effect of non-controlling interests (note 15)	(10,546)	(3,024)	(49,279)	(23,123)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 59,440	$ 17,745	$ 133,114	$ 84,578
Series A and D Preferred shares dividend (note 13)	2,600	2,600	7,800	7,800
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	$ 56,840	$ 15,145	$ 125,314	$ 76,778
Basic net earnings per share (note 17)	$ 0.15	$ 0.06	$ 0.34	$ 0.28
Diluted net earnings per share (note 17)	$ 0.15	$ 0.05	$ 0.33	$ 0.28

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 September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Net earnings	$ 48,894	$ 14,721	$ 83,835	$ 61,455
Other comprehensive income:				
Foreign currency translation adjustment, net of tax recovery of $247 and $991 (2016 - tax recovery of $nil and $nil), respectively (notes 21(b)(iii) and 21(b)(iv))	(133,578)	53,659	(274,649)	(128,367)
Change in fair value of cash flow hedges, net of tax expense of $3,834 and $4,827 (2016 - tax expense of $4,746 and recovery of $1,341), respectively (note 21(b)(ii))	6,911	(19,789)	8,481	(6,148)
Change in unrealized appreciation in value of available-for-sale investments	—	(7)	(26)	20
Change in pension and other post-employment benefits, net of tax expense of $39 and $1,236 (tax expense of $137 and recovery of $2,257), respectively (note 8)	36	263	1,977	(3,532)
Other comprehensive (loss) income, net of tax	(126,631)	34,126	(264,217)	(138,027)
Comprehensive (loss) income	(77,737)	48,847	(180,382)	(76,572)
Comprehensive (loss) income attributable to the non-controlling interests	(39,062)	1,174	(106,594)	(43,006)
Comprehensive (loss) income attributable to shareholders of Algonquin Power & Utilities Corp.	$ (38,675)	$ 47,673	$ (73,788)	$ (33,566)

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 nine months ended September 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)	—	—	—	133,114	—	(49,279)	83,835
Redeemable non-controlling interests not included in equity (note 15)	—	—	—	—	—	10,379	10,379
Other comprehensive loss	—	—	—	—	(206,902)	(57,315)	(264,217)
Dividends declared and distributions to non-controlling interests	—	—	—	(152,735)	—	(3,685)	(156,420)
Dividends and issuance of shares under dividend reinvestment plan	33,550	—	—	(33,550)	—	—	—
Common shares issued upon conversion of convertible debentures	1,113,292	—	—	—	—	—	1,113,292
Common shares issued pursuant to share-based awards (note 11(b))	19,496	—	(6,369)	(1,946)	—	—	11,181
Share-based compensation (note 11(b))	—	—	7,463	—	—	—	7,463
Contributions received from non-controlling interests (notes 3(a), 3(e) and 6(a))	—	—	—	—	—	263,462	263,462
Balance, September 30, 2017	$ 3,138,541	$ 213,805	$ 39,746	$ (611,141)	$ 48,025	$ 725,920	$ 3,554,896

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 September 30		Nine Months Ended September 30	
	2017	2016	2017	2016
Cash provided by (used in):				
Operating Activities				
Net earnings	$ 48,894	$ 14,721	$ 83,835	$ 61,455
Adjustments and items not affecting cash:				
Depreciation and amortization	80,045	41,605	251,359	142,875
Deferred taxes	11,620	(737)	46,470	17,732
Unrealized loss (gain) on derivative financial instruments	1,439	(6,754)	4,421	(5,732)
Share-based compensation expense	2,620	1,449	7,181	4,083
Cost of equity funds used for construction purposes	(711)	(857)	(1,846)	(1,945)
Pension and post-employment expense	(18,965)	(6,497)	(13,252)	(9,273)
Non-cash revenue and other income	110	(1,607)	(208)	(7,182)
Write-down (gain) on long-lived assets	849	(2)	(3,980)	6,936
Changes in non-cash operating items (note 20)	(6,755)	(18,725)	(86,030)	(42,974)
	119,146	22,596	287,950	165,975
Financing Activities				
Increase in long-term debt	224,531	174,116	1,738,740	527,357
Decrease in long-term debt	(80,819)	—	(2,483,980)	(48,049)
Issuance of convertible debentures, net of costs	—	(422)	743,881	357,880
Cash dividends on common shares	(44,240)	(30,027)	(127,089)	(87,846)
Cash dividends on preferred shares	(2,600)	(2,600)	(7,800)	(7,800)
Cash contributions from non-controlling interests	14,004	—	293,637	—
Production-based cash contributions from non-controlling interest	—	—	10,622	9,454
Cash distributions to non-controlling interests	(1,670)	(777)	(3,071)	(3,204)
Issuance of common shares, net of costs	68	364	184	1,045
Proceeds from settlement of derivative assets	—	—	48,380	—
Proceeds from exercise of share options	—	(1,000)	12,761	18,493
Shares surrendered to fund withholding taxes on exercised share options	—	—	(4,293)	(5,218)
Increase in other long-term liabilities	535	23	16,340	4,252
Decrease in other long-term liabilities	(836)	(379)	(7,219)	(3,200)
	108,973	139,298	231,093	763,164
Investing Activities				
Increase (decrease) in restricted cash	5,099	(3,949)	2,015,239	—
Acquisitions of operating entities	—	(100,005)	(2,047,401)	(432,283)
Divestiture of operating entity	—	—	111,043	—
Additions to property, plant and equipment	(165,434)	(92,257)	(569,857)	(233,959)
Decrease (increase) in other assets	101	2,181	(2,648)	(10,942)
Distributions received in excess of equity income	2,444	2,024	2,834	1,454
Receipt of principal on notes receivable	—	—	—	11,685
Increase in long-term investments	(15,191)	(196,166)	(49,368)	(338,111)
	(172,981)	(388,172)	(540,158)	(1,002,156)
Effect of exchange rate differences on cash	(10,533)	4,720	(12,840)	(3,816)
Increase (decrease) in cash and cash equivalents	44,605	(221,558)	(33,955)	(76,833)
Cash and cash equivalents, beginning of period	31,857	269,078	110,417	124,353
Cash and cash equivalents, end of period	$ 76,462	$ 47,520	$ 76,462	$ 47,520

Supplemental disclosure of cash flow information:	2017	2016	2017	2016
Cash paid during the period for interest expense	$ 50,013	$ 47,492	$ 140,437	$ 106,414
Cash paid during the period for income taxes	$ 1,778	$ 2,244	$ 10,111	$ 10,931
Non-cash financing and investing activities:				
Property, plant and equipment acquisitions in accruals	$ 142,116	$ 38,613	$ 142,116	$ 38,613
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	$ 15,260	$ 7,406	$ 36,262	$ 26,994
Issuance of common shares upon conversion of convertible debentures (note 10)	$ 562	$ —	$1,100,924	$ —
Issuance of common shares upon conversion of subscription receipts	$ —	$ 110,503	$ —	$ 110,503
Acquisition of equity investments in exchange of loan receivable and payable	$ 2,353	$ 22,153	$ 2,353	$ 22,153

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(c)). 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 and during the nine months ended September 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	$ 822,730
Accumulated Depreciation	$ 222,499
Expenditures	$ 76,261

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 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities, to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. The update also makes certain targeted improvements to simplify the application of the hedge accounting guidance. The update is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years . Early application is permitted in any interim period after issuance of the update. The Company is currently assessing the impacts of this update.

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. The Company will apply the guidance in this update for future modifications.

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 Post-retirement Benefit Cost, to improve the reporting of defined benefit pension cost and post-retirement 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. No impact on the consolidated financial statements is expected from the adoption of this update.

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 is in the final stages of the impact assessment. At this point, the Company does not expect changes to the pattern of revenue recognition and is considering adopting the new revenue recognition standard using the modified retrospective method. A final evaluation of the impact on internal controls and financial statement disclosures is being finalized. The Company is on track for implementation of this standard by the effective date.

3. Business acquisitions and development projects

(a) Great Bay Solar Project

On August 12, 2015, the Company acquired rights to develop a 75 MWac solar project in Somerset County, Maryland. The project consists of four separate sites and is expected to be placed in service in Q4 2017. As of September 30, 2017, two of the four sites had been synchronized with the power grid.

The Great Bay Solar Facility is controlled by a subsidiary of APUC ("Great Bay Holdings, LLC"). On September 18, 2017, an equity capital contribution agreement was signed with a third-party tax equity investor committing to total funding of U.S. $62,500 in consideration for Class A membership interests. Initial equity capital contribution of U.S. $12,500 was received on September 18, 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.

3. Business acquisitions and development projects (continued)

(b) Acquisition of the St. Lawrence Gas Company, Inc.

On August 31, 2017, the Company entered into a definitive agreement to acquire St. Lawrence Gas Company, Inc. ("SLG"). SLG is a rate-regulated natural gas distribution utility serving approximately 16,000 customers in northern New York state. The total purchase price for the transaction is U.S. $70,000, less total third-party debt of SLG outstanding at closing, and subject to customary working capital adjustments. Closing of the transaction remains subject to regulatory approval and other closing conditions and is expected to occur in late 2018 or early 2019.

(c) 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.

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

Working capital	$ 54,874
Property, plant and equipment	2,764,905
Goodwill	990,828
Regulatory assets	281,695
Other assets	52,347
Long-term debt	(1,218,563)
Regulatory liabilities	(112,920)
Pension and other post-employment benefits	(107,907)
Deferred income tax liability, net	(579,317)
Other liabilities	(103,317)
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.

3. Business acquisitions and development projects (continued)

(c) Acquisition of Empire (continued)

The table below presents the unaudited consolidated pro forma revenue and net income for the three and nine months ended ended September 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 September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenues	**$ 443,316**	$ 449,953	**$ 1,454,456**	$ 1,401,497
Net earnings attributable to common shareholders	**$ 55,517**	$ 33,841	**$ 181,119**	$ 168,274

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.

(d) 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 September 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.

(e) 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.

3. Business acquisitions and development projects (continued)

(e) Bakersfield II Solar Facility (continued)

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 September 30, 2017 include unbilled revenue of $47,280 (December 31, 2016 - $57,822) from the Company's regulated utilities. Accounts receivable as of September 30, 2017 are presented net of allowance for doubtful accounts of $7,718 (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 August 2017, the Corporation Commission of the State of Oklahoma approved an Environmental Compliance Rider of U.S. $992 annually effective August 31, 2017.

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.

5. Regulatory matters (continued)

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.

Regulatory assets and liabilities consist of the following:

	September 30, 2017	December 31, 2016
Regulatory assets		
Environmental remediation	**$ 97,437**	$ 104,160
Pension and post-employment benefits	**140,745**	75,527
Debt premium	**75,093**	25,173
Fuel and commodity costs adjustments	**26,243**	6,972
Rate adjustment mechanism	**47,227**	40,602
Clean Energy and other customer programs	**25,081**	2,106
Deferred construction costs (a)	**17,988**	—
Asset retirement	**18,490**	2,113
Income taxes	**34,231**	10,182
Rate case costs	**9,021**	8,572
Other	**33,589**	16,557
Total regulatory assets	**$ 525,145**	$ 291,964
Less current regulatory assets	**(74,148)**	(48,440)
Non-current regulatory assets	**$ 450,997**	$ 243,524
Regulatory liabilities		
Cost of removal	**$ 159,564**	$ 110,330
Rate-base offset	**17,236**	20,946
Fuel and commodity costs adjustments	**41,789**	33,891
Deferred compensation received in relation to lost production	**12,450**	—
Deferred construction costs - fuel related (a)	**9,294**	—
Pension and post-employment benefits	**10,249**	5,481
Income Taxes	**7,070**	1,501
Other	**13,021**	10,585
Total regulatory liabilities	**$ 270,673**	$ 182,734
Less current regulatory liabilities	**(53,946)**	(47,769)
Non-current regulatory liabilities	**$ 216,727**	$ 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:

	September 30, 2017	December 31, 2016
Equity-method investees		
Red Lily	**$ 21,670**	$ 23,504
Deerfield Wind Project (a)	**—**	34,727
Amherst Island Wind Project	**1,881**	558
Other	**6,101**	5,630
	$ 29,652	$ 64,419
Notes receivable		
Development loans (b)	**$ 78,551**	$ 32,125
Other	**4,119**	6,058
	82,670	38,183
Available-for-sale investment	**—**	169
Other investments	**2,536**	2,662
Total long-term investments	**114,858**	105,433
Less current portion classified within other assets	**(4,453)**	—
Total long-term investments	**$ 110,405**	$ 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 September 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 project developer in the United States.

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 are 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	September 30, 2017	December 31, 2016
Senior Unsecured Revolving Credit Facilities (a)	**$ 653,433**	$ 242,947
Senior Unsecured Bank Credit Facilities (b)	**168,480**	2,140,122
Canadian Dollar Borrowings		
Senior Unsecured Notes (c)	**781,566**	487,389
Senior Secured Project Notes	**34,032**	35,600
U.S. Dollar Borrowings		
Senior Unsecured Notes (d)	**1,519,502**	700,600
Senior Unsecured Utility Notes (e)	**281,599**	174,206
Senior Secured Utility Bonds (f)	**993,837**	132,551
	$ 4,432,449	$ 3,913,415
Less: current portion	**(8,426)**	(10,075)
	$ 4,424,023	$ 3,903,340

Long-term debt issued at a subsidiary level (project notes, utility notes or utility bonds) 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 $681,800 for which the maturity has been extended beyond 12 months subsequent to the end of the quarter or that are expected to be refinanced using the long-term credit facilities are presented as long-term debt.

7. Long-term debt (continued)

(a) Senior unsecured revolving credit facilities

During the quarter, the Company increased its APUC credit facility from $65,000 to $165,000 and the maturity was extended to November 19, 2018.

Subsequent to quarter end on October 6, 2017 the Liberty Power Group's revolving credit facility was increased to U.S. $500,000 and the maturity was extended to October 6, 2022.

Liberty Power entered into a $150,000 bilateral revolving credit facility on April 19, 2017 with a maturity date of August 19, 2018. Drawings under the facility of $118,685 at September 30, 2017 were fully repaid on October 6, 2017.

As at September 30, 2017, the Liberty Utilities Group's committed bank lines consisted of a U.S. $200,000 senior unsecured revolving credit facility and a U.S. $200,000 revolving credit facility at Empire ("Empire Facility") assumed in connection with the acquisition of Empire (note 3(c)). 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.

(b) Senior unsecured bank credit facilities

On December 30, 2016, in connection with the acquisition of Empire (note 3(c)), 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(c)) 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.

Subsequent to quarter end, the Liberty Utilities Group extended the maturity on its term loan facility to July 5, 2019.

(c) Canadian dollar senior unsecured notes

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

In September 2017, the Company acquired an investment in an equity-investee in exchange for a note payable to the other partner of $669. Repayment of the note is expected in 2019.

(d) U.S. dollar senior unsecured notes

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

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

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

On January 1, 2017, in connection with the acquisition of Empire (note 3(c)), 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%.

7. Long-term debt (continued)

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

On January 1, 2017 in connection with the acquisition of Empire (note 3(c)), 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).

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

On March 14, 2017, in connection with the acquisition of Deerfield SponsorCo (note 6(a)), the Company assumed U.S. $262,219 in construction loan. The loans bear interest at an annual rate of 2.33% on any outstanding principal amount. 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.

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

	Pension benefits			
	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	2017	2016
Service cost	**$ 4,249**	$ 2,132	**$ 13,853**	$ 6,482
Interest cost	**6,237**	3,150	**19,540**	9,578
Expected return on plan assets	**(8,089)**	(3,419)	**(24,917)**	(10,394)
Amortization of net actuarial loss	**376**	742	**1,088**	2,257
Amortization of prior service credits	**(195)**	(188)	**(610)**	(572)
Amortization of regulatory asset/liability	**3,635**	1,085	**11,376**	3,298
Net benefit cost	**$ 6,213**	$ 3,502	**$ 20,330**	$ 10,649

	OPEB			
	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	2017	2016
Service cost	**$ 1,528**	$ 796	**$ 4,937**	$ 2,419
Interest cost	**2,037**	904	**6,498**	2,751
Expected return on plan assets	**(2,044)**	(298)	**(6,367)**	(906)
Amortization of net actuarial loss	**(130)**	136	**(226)**	414
Amortization of prior service credits	**(82)**	(453)	**(256)**	(1,377)
Amortization of regulatory asset/liability	**336**	246	**1,052**	749
Net benefit cost	**$ 1,645**	$ 1,331	**$ 5,638**	$ 4,050

9. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

	September 30, 2017	December 31, 2016
Advances in aid of construction	**$ 76,789**	$ 105,191
Environmental remediation obligations	**61,366**	63,378
Asset retirement obligations	**55,317**	24,822
Customer deposits	**34,336**	14,881
Unamortized investment tax credits	**22,350**	—
Hook up fees	**7,554**	12,039
Deferred income	**1,442**	—
Deferred credits	**26,436**	44,544
Other	**30,444**	10,751
	316,034	275,606
Less current portion	**(44,842)**	(43,157)
	$ 271,192	$ 232,449

9. Other long-term liabilities and deferred credits (continued)

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

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

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

10. Convertible Unsecured Subordinated Debentures

Maturity date		March 31, 2026
Interest rate		5.00%
Conversion price per share	$	10.60
Carrying value at December 31, 2016	$	358,619
Receipt of Final instalment, net of deferred financing costs		743,881
Amortization of deferred financing costs		1,139
Conversion to common shares	$	(1,101,036)
Carrying value at September 30, 2017	$	2,603
Face value at September 30, 2017	$	2,717

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(c)). 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 nine months ended September 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 September 30, 2017, a total of 108,234,197 common shares of the Company were issued (note 11), representing conversion into common shares of more than 99.76% 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)	108,234,197
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	3,245,606
Common shares, end of period	387,036,183

(b) Share-based compensation

During the nine months ended September 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 nine months ended September 30, 2017, 43,493 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 nine months ended September 30, 2017, APUC recorded $2,675 and $7,192 (2016 - $1,581 and $4,073) 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 September 30, 2017, total unrecognized compensation costs related to non-vested options and PSUs were $3,632 and $8,185, respectively, and are expected to be recognized over a period of 1.55 and 2.03 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	(217,334)	14,403	(26)	1,921	(201,036)
Amounts reclassified	—	(5,922)	—	56	(5,866)
Net current period OCI	$(217,334)	$ 8,481	$ (26)	$ 1,977	$ (206,902)
Balance, September 30, 2017	$ (17,006)	$ 74,564	$ 115	$ (9,648)	$ 48,025

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 nine months ended September 30, 2017 and 2016 were as follows:

	Three Months Ended September 30			
	2017		2016	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	**$ 57,517**	**$ 0.1480**	$ 37,735	$ 0.1377
Series A preferred shares	**$ 1,350**	**$ 0.2813**	$ 1,350	$ 0.2813
Series D preferred shares	**$ 1,250**	**$ 0.3125**	$ 1,250	$ 0.3125

	Nine Months Ended September 30			
	2017		2016	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	**$ 178,485**	**$ 0.4606**	$ 109,937	$ 0.4025
Series A preferred shares	**$ 4,050**	**$ 0.8438**	$ 4,050	$ 0.8438
Series D preferred shares	**$ 3,750**	**$ 0.9375**	$ 3,750	$ 0.9375

14. Related party transactions

Emera Inc.

An executive at Emera was a member of the Board of APUC until June 8, 2017. The Energy Services Business sold electricity to Maine Public Service Company and Bangor Hydro, both of which are subsidiaries of Emera. The portion considered related party transactions during the three and nine months ended September 30, 2017, amounts to U.S. $nil and $4,397 (2016 - U.S. $3,095 and $7,951). The Liberty Utilities Group purchased natural gas from Emera for its gas utility customers. The portion considered related party transactions during the three and nine months ended September 30, 2017, amounts to U.S. $nil and $1,006 (2016 - U.S. $534 and $2,762). 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 fourth 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. $1,711 included in accruals for the nine months ended September 30, 2017 (2016 - U.S. $64) 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 $704 and $1,512 (2016 - $893 and $2,510) during the three and nine months ended September 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 remains outstanding.

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 nine months ended September 30, 2017 and 2016 consists of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
HLBV and other adjustments attributable to:				
Non-controlling interest -Class A partnership units	**$ (7,823)**	$ (3,811)	**$ (41,266)**	$ (23,254)
Non-controlling interest -redeemable Class A partnership units	**(3,308)**	(1,378)	**(10,379)**	(4,127)
Other net earnings attributable to non-controlling interests	**585**	2,165	**2,366**	4,258
Net effect of non-controlling interests	**$ (10,546)**	$ (3,024)	**$ (49,279)**	$ (23,123)

Contributions from new Class A partnership investors of U.S. $12,500 was received for the Great Bay Solar Facility on September 18, 2017 (note 3(a)); U.S. $9,800 was received for the Bakersfield II Solar Facility on February 28, 2017 (note 3(e)); and, U.S. $166,595 was received for the Deerfield Wind Project on May 10, 2017 (note 6(a)).

16. Income taxes

For the nine months ended September 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. 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 nine months ended September 30, 2017 and 2016 are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
Net earnings attributable to shareholders of APUC	**$ 59,440**	$ 17,745	**$ 133,114**	$ 84,578
Series A Preferred shares dividend	**1,350**	1,350	**4,050**	4,050
Series D Preferred shares dividend	**1,250**	1,250	**3,750**	3,750
Net earnings attributable to common shareholders of APUC – Basic and Diluted	**$ 56,840**	$ 15,145	**$ 125,314**	$ 76,778
Weighted average number of shares				
Basic	**386,816,307**	273,202,368	**372,109,455**	271,120,426
Effect of dilutive securities	**3,438,243**	2,376,823	**3,696,938**	2,433,527
Diluted	**390,254,550**	275,579,191	**375,806,393**	273,553,953

The shares potentially issuable, for the three and nine months ended September 30, 2017, as a result of 2,328,343 and 1,897,266 share options (2016 - 108,424 and 1,417,500) 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.

18. Segmented information (continued)

	Three Months Ended September 30, 2017			
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	$ 59,997	$ 383,319	$ —	$ 443,316
Fuel, power and water purchased	5,379	98,483	—	103,862
Net revenue	54,618	284,836	—	339,454
Operating expenses	22,490	119,789	—	142,279
Administrative expenses	4,817	9,401	220	14,438
Depreciation and amortization	20,249	50,824	334	71,407
Gain on foreign exchange	—	—	2,643	2,643
Operating income	7,062	104,822	(3,197)	108,687
Interest expense	12,114	32,716	783	45,613
Interest, dividend, equity and other income	(699)	(1,189)	(567)	(2,455)
Other expenses (gain)	(16)	818	1,050	1,852
Earnings (loss) before income taxes	$ (4,337)	$ 72,477	$ (4,463)	$ 63,677
Capital expenditures	61,434	104,000	—	165,434

	Three Months Ended September 30, 2016			
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	$ 60,730	$ 160,547	$ —	$ 221,277
Fuel and power purchased	6,018	41,147	—	47,165
Net revenue	54,712	119,400	—	174,112
Operating expenses	17,386	62,948	15	80,349
Administrative expenses	4,863	6,902	306	12,071
Depreciation and amortization	15,385	24,008	340	39,733
Loss on foreign exchange	—	—	(3,355)	(3,355)
Operating income (loss)	17,078	25,542	2,694	45,314
Interest expense	5,123	12,335	17,309	34,767
Interest, dividend and other income	561	(1,351)	(715)	(1,505)
Other expense (gain)	(1,684)	(4,926)	2,146	(4,464)
Earnings (loss) before income taxes	$ 13,078	$ 19,484	$ (16,046)	$ 16,516
Capital expenditures	25,074	67,183	—	92,257

18. Segmented information (continued)

	Nine Months Ended September 30, 2017			
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	$ 213,363	$ 1,241,093	$ —	$ 1,454,456
Fuel, power and water purchased	17,679	348,625	—	366,304
Net revenue	195,684	892,468	—	1,088,152
Operating expenses	64,731	388,908	—	453,639
Administrative expenses	15,524	29,571	651	45,746
Depreciation and amortization	73,766	163,655	1,001	238,422
Gain on foreign exchange	—	—	(1,193)	(1,193)
Operating income	41,663	310,334	(459)	351,538
Interest expense	35,940	96,841	27,437	160,218
Interest, dividend, equity and other income	(2,614)	(3,678)	(2,222)	(8,514)
Other expenses (gain)	2,285	(4,988)	61,501	58,798
Earnings (loss) before income taxes	$ 6,052	$ 222,159	$ (87,175)	$ 141,036
Property, plant and equipment	$ 2,812,547	$ 4,934,213	$ 43,661	$ 7,790,421
Equity-method investees	26,420	997	2,235	29,652
Total assets	3,113,811	7,066,260	126,666	10,306,737
Capital expenditures	179,873	389,984	—	569,857

	Nine Months Ended September 30, 2016			
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	$ 192,049	$ 593,735	$ —	$ 785,784
Fuel and power purchased	15,042	190,392	—	205,434
Net revenue	177,007	403,343	—	580,350
Operating expenses	52,167	192,519	45	244,731
Administrative expenses	13,911	18,380	1,573	33,864
Depreciation and amortization	55,770	77,478	1,019	134,267
Gain on foreign exchange	—	—	(1,782)	(1,782)
Operating income (loss)	55,159	114,966	(855)	169,270
Interest expense	14,878	37,470	40,549	92,897
Interest, dividend and other income	(160)	(4,006)	(2,269)	(6,435)
Other expense (gain)	(14,519)	1,875	8,366	(4,278)
Earnings (loss) before income taxes	$ 54,960	$ 79,627	$ (47,501)	$ 87,086
Capital expenditures	86,313	147,646	—	233,959
	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. $4,370.

(b) Commitments

In addition to the commitments related to the business acquisition and development projects disclosed in notes 3 and 6, the following significant commitments exist as of September 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)	$ 62,830	$ 47,817	$ 49,228	$ 49,884	$ 50,162	$ 256,647	$ 516,568
Gas supply and service agreements (ii)	97,602	70,487	56,256	34,916	29,585	98,946	387,792
Service agreements	45,380	45,837	47,690	48,398	46,501	444,763	678,569
Capital projects	24,319	—	—	—	—	—	24,319
Operating leases	10,057	9,735	8,754	8,809	8,899	229,185	275,439
Total	$240,188	$173,876	$161,928	$142,007	$135,147	$1,029,541	$1,882,687

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 September 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 September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Accounts receivable	**$ (8,203)**	$ 5,126	**$ 56,385**	$ 58,345
Fuel and natural gas in storage	**(6,840)**	(8,033)	**(3,277)**	5,084
Supplies and consumable inventory	**(4,937)**	(935)	**(4,634)**	(430)
Income taxes receivable	**3,026**	(787)	**816**	910
Prepaid expenses	**10,316**	4,282	**3,905**	(1,551)
Accounts payable	**(3,280)**	25	**(84,962)**	(40,424)
Accrued liabilities	**1,756**	(15,356)	**(33,990)**	(54,877)
Current income tax liability	**(6,663)**	929	**(5,967)**	(3,972)
Net regulatory assets and liabilities	**8,070**	(3,976)	**(14,306)**	(6,059)
	$ (6,755)	$ (18,725)	**$ (86,030)**	$ (42,974)

21. Financial instruments

(a) Fair value of financial instruments

September 30, 2017	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 82,670	$ 83,718	$ —	$ 83,718	$ —
Derivative instruments:					
Energy contracts designated as a cash flow hedge	88,657	88,657	—	—	88,657
Currency forward contract not designated as a hedge	497	497	—	497	—
Commodity contracts for regulated operations	582	582	—	582	—
Transmission congestion rights	8,766	8,766	—	8,766	—
Total derivative instruments	98,502	98,502	—	9,845	88,657
Total financial assets	$ 181,172	$ 182,220	$ —	$ 93,563	$ 88,657
Long-term debt	$ 4,432,449	$ 4,641,691	$ 817,475	$ 3,824,216	$ —
Convertible debentures	2,603	2,717	2,717	—	—
Preferred shares, Series C	18,459	18,320	—	18,320	—
Derivative instruments:					
Cross-currency swap designated as a net investment hedge	71,414	71,414	—	71,414	—
Interest rate swap designated as a hedge	10,465	10,465	—	10,465	—
Commodity contracts for regulated operations	2,080	2,080	—	2,080	—
Total derivative instruments	83,959	83,959	—	83,959	—
Total financial liabilities	$ 4,537,470	$ 4,746,687	$ 820,192	$ 3,926,495	$ —

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 September 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. Transmission congestion rights ("TCR") positions are fair valued using the most recent monthly auction clearing prices.

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 $21.53 to $111.33 with a weighted average of $31.81 as of September 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 nine months ended September 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	2,687,886
	Options	858,077
	Forward contracts	13,420,000
		16,965,963

At September 30, 2017, TCR of 6,328 monthly MW-hrs 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:

		September 30, 2017		December 31, 2016
Regulatory assets:				
Swap contracts	U.S. $	**83**	U.S. $	—
Option contracts	U.S. $	**311**	U.S. $	27
Forward contracts	U.S. $	**4,621**	U.S. $	—
Regulatory liabilities:				
Swap contracts	U.S. $	**23**	U.S. $	175
Option contracts	U.S. $	**—**	U.S. $	92
Forward contracts	U.S. $	**15,111**	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)
604,108	December 2022	U.S. $	42.81	PJM Western HUB
2,587,441	December 2022	U.S. $	30.25	NI HUB
3,430,217	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 for the three and nine months ended September 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 $2,656 and $2,919 for the three and nine months ended September 30, 2017 (2016 - loss of $1,758 and $13,174), 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 September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Effective portion of cash flow hedge	**$ 8,440**	$ (17,052)	**$ 14,429**	$ 1,877
Amortization of cash flow hedge	**(9)**	(14)	**(26)**	(30)
Gain reclassified from AOCI	**(1,520)**	(2,723)	**(5,922)**	(7,995)
OCI attributable to shareholders of APUC	**$ 6,911**	$ (19,789)	**$ 8,481**	$ (6,148)

The Company expects $12,374 and $2,630 of gains currently in AOCI to be reclassified, net of taxes 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 gain of $15,287 and $25,890 for the three and nine months ended September 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 nine months ended September 30, 2017, a gain of $25,120 and $20,142 (2016 - loss of $5,767 and gain of $9,020) 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 September 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(c)). 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 nine months ended September 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 nine months ended September 30, 2017, a gain on foreign exchange of $1,386 and $497 (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 September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Change in unrealized gain on derivative financial instruments:				
Energy derivative contracts	**$ —**	$ —	**$ —**	$ (426)
Currency forward contracts	**(1,362)**	(7,261)	**(497)**	(6,843)
Total change in unrealized gain on derivative financial instruments	**$ (1,362)**	$ (7,261)	**$ (497)**	$ (7,269)
Realized loss (gain) on derivative financial instruments:				
Interest rate swaps	**—**	—	**(193)**	—
Energy derivative contracts	**—**	—	**730**	941
Currency forward contracts	**—**	4,229	**16,413**	(1,371)
Total realized loss (gain) on derivative financial instruments	**$ —**	$ 4,229	**$ 16,950**	$ (430)
Loss (gain) on derivative financial instruments not accounted for as hedges	**(1,362)**	(3,032)	**16,453**	(7,699)
Ineffective portion of derivative financial instruments accounted for as hedges	**(14)**	507	**819**	1,509
	$ (1,376)	$ (2,525)	**$ 17,272**	$ (6,190)
Amounts recognized in the consolidated statements of operations consist of:				
Loss (gain) on derivative financial instruments	**(14)**	(4,419)	**1,356**	(2,902)
Loss (gain) on foreign exchange	**(1,362)**	1,893	**15,916**	(3,289)
	$ (1,376)	$ (2,526)	**$ 17,272**	$ (6,191)

(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. Subsequent events

(a) Investment in joint venture with Abengoa and investment in Atlantica

On November 1, 2017, APUC entered into an agreement to create a joint venture ("AAGES") with Seville, Spain-based Abengoa, S.A ("Abengoa") to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Concurrently with the creation of the AAGES joint venture, APUC entered into a definitive agreement to purchase from Abengoa a 25% equity interest in Atlantica Yield plc ("Atlantica") for a total purchase price of approximately U.S. $608,000, based on a price of U.S. $24.25 per ordinary share of Atlantica plus a contingent payment of up to U.S. $0.60 per-share payable two years after closing, subject to certain conditions. The transaction is expected to close in the first quarter of 2018, subject to regulatory approvals and other closing conditions. No shareholder approvals are required.

(b) Bought Deal Offering of Common Shares

On November 10, 2017, APUC announced that it closed a bought deal offering announced on November 1, 2017, including the exercise in full of the underwriters' over-allotment option. As a result, a total of 43,470,000 common shares of APUC were sold at a price of $13.25 for gross proceeds of approximately $576,000. Net proceeds of the offering are expected to be used, in part, to finance APUC's acquisition of Abengoa's 25% ownership stake in Atlantica and for general corporate purposes.

(c) Approval to acquire the Perris Water Distribution System

On August 10, 2017 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. $11,500 is expected to be established as rate base during the regulatory approval process. The City of Perris residents voted to approve the sale on November 7, 2017. Liberty Utilities will now file an application to acquire the water utility with the California Public Utility Commission. Approval of the acquisition of the utility is expected in 2018.

23. Comparative figures

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

CORPORATE INFORMATION

DIRECTORS

Kenneth Moore, Chairman – Managing Partner, NewPoint Capital Partners Inc.
Christopher Ball – Executive Vice President, Corpfinance International Ltd.
Chris Jarratt – Vice Chair, Algonquin Power & Utilities Corp.
D. Randy Laney – Former Chairman of the Board, The Empire District Electric Company
Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.
Masheed Saidi – Former Executive VP and Chief Operating Officer, U.S. Transmission, Natural Grid USA
Dilek Samil – Former Executive VP and Chief Operating Officer, NV Energy
Melissa Stapleton Barnes – Senior VP, Enterprise Risk Management, and Chief Ethics and Compliance Officer, Eli Lilly and Company
George Steeves – Principal, True North Energy

THE EXECUTIVE TEAM

Ian Robertson, Chief Executive Officer
Chris Jarratt, Vice Chair
David Bronicheski, Chief Financial Officer
Linda Beairsto, Chief Compliance Officer
Jeff Norman, Chief Development Officer
David Pasieka, Chief Operations Officer, Liberty Utilities Group
Mike Snow, Chief Operations Officer, Liberty Power Group
Jennifer Tindale, Chief Legal Officer
George Trisic, Chief Administration Officer and Corporate Secretary

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