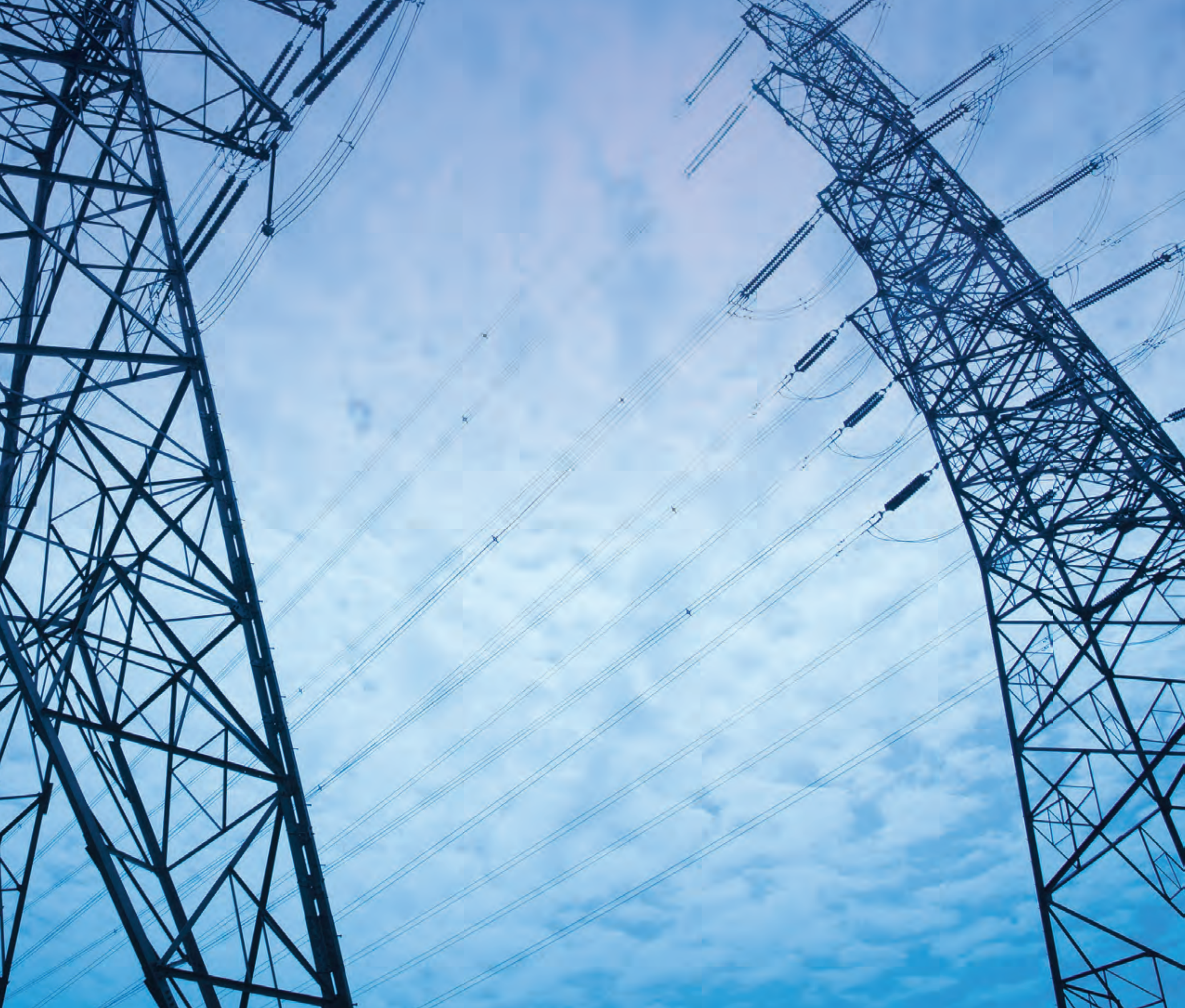
ALGONQUIN
Power & Utilities Corp.

Q3 2015

Algonquin Power & Utilities is a $4.5 billion North American diversified generation, transmission and distribution utility.

Our vision is clear: To be most admired by customers, communities and investors for our people, passion and performance.



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, 2015. 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, 2015 and 2014. The MD&A should also be read in conjunction with APUC's annual audited consolidated financial statements for the years ended December 31, 2014 and 2013, and the annual MD&A for the year ended December 31, 2014. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Capitalized terms used herein and not otherwise defined will have the meanings assigned to them in the Corporation's 2014 Annual Information Form.

This MD&A is based on information available to management as of November 5, 2015.

Caution concerning forward-looking statements and non-GAAP Measures

Forward-looking statements

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets and 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", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales", "net energy/steam sales", and "net utility sales", are used throughout this MD&A. The terms "adjusted net earnings", "per share cash provided by operating activities", "adjusted funds from operations", "per share cash provided by adjusted funds from operations", Adjusted EBITDA, "net energy sales", "net energy/steam sales", and "net utility sales" are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales", "net energy/steam sales", and "net utility sales" 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", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales", "net energy/steam sales", and "net utility sales" can be found throughout this MD&A. Per share cash provided by operating activities is not a substitute measure of performance for earnings per share. Amounts represented by per share cash provided by operating activities do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

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 and are viewed as not directly related to a company's operating performance. Net earnings of APUC can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps and energy forward purchase contracts as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. 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.

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 and are viewed as not directly related to a company's operating performance. Cash flows from operating activities of APUC can be impacted positively or negatively by changes in working capital balances, acquisition expenses, litigation expenses cash provided or used in discontinued operations. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. 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 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.

Net Energy Sales & Net Energy/Steam Sales

Net energy sales and net energy/steam sales are a non-GAAP measure used by investors to identify revenue after commodity costs used to generate revenue where revenue generally is increased or decreased in response to increases or decreases in the cost of the commodity to produce that revenue. APUC uses net energy sales and net energy/steam 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 revenue that is charged. APUC believes that analysis and presentation of net energy sales and net energy/steam 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 commodities 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 the utility customer. 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. Capitalized terms used herein and not otherwise defined will have the meanings assigned to them in the Corporation's 2014 Annual Information Form.

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 a quarterly dividend augmented by share price appreciation arising from dividend growth supported by increasing per share cash flows and earnings.

APUC's current quarterly dividend to shareholders is U.S. $0.09625 per share or U.S. $0.3850 per share per annum. Based on exchange rates as at November 5, 2015, the quarterly dividend is equivalent to Cdn $0.12673 per share or Cdn $0.50693 per 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 and mitigate the impact of fluctuations in foreign exchange rates. 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 three business units consisting of Generation, Transmission and Distribution. The Generation Business Group ("Generation Group") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the recently formed Transmission Business Group ("Transmission Group") is responsible for evaluating and capitalizing upon natural gas pipeline and electric transmission asset opportunities in North America; and the Distribution Business Group ("Distribution Group") owns and operates a portfolio of North American electric, natural gas and water distribution and wastewater collection utility systems.

Generation Business Group

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

The Generation Group owns or has interests in hydroelectric, wind, and solar facilities with a combined generating capacity of approximately 120 MW, 700 MW, and 30 MW, respectively. Approximately 83% of the electrical output from the hydroelectric, wind and solar generating facilities is sold pursuant to long-term contractual arrangements which have a weighted average remaining contract life of 14 years.

The Generation Group owns or has interests in thermal energy facilities with approximately 335 MW of installed generating capacity. Approximately 91% of the electrical output from the owned thermal facilities is sold pursuant to long term power purchase agreements ("PPA") with major utilities, which have a weighted average remaining contract life of 7 years.

The Generation Group also has a portfolio of development projects that between 2016 and 2018 will add approximately 636 MW of generation capacity from wind and solar powered generating stations with an average contract life of 23 years.

Distribution Business Group

The Distribution Group operates diversified rate regulated electricity, natural gas, water distribution and wastewater collection utility services to approximately 488,000 connections. The Distribution Group provides safe, high quality and reliable services to its customers through its nationwide portfolio of utility systems and delivers stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Distribution Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

The Distribution Group's regulated electrical distribution utility systems and related generation assets are located in the States of California and New Hampshire; and together serve approximately 93,000 electric connections.

The Distribution Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, Missouri and New Hampshire; and together serve approximately 292,000 natural gas connections.

The Distribution Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, Illinois, Missouri, and Texas; and together serve approximately 103,000 connections.

Transmission Business Group

The Transmission Group complements the growth of both the Generation and Distribution Groups and is responsible for identifying, evaluating and capitalizing upon natural gas pipeline and electric transmission investment opportunities in North America.

Major Highlights

2015 Corporate Highlights

Declaration of Canadian equivalent fourth quarter dividend of Cdn $0.12673 (U.S. $0.09625) per Common Share

On November 5, 2015, APUC announced that the Board of Directors of APUC declared the fourth quarter 2015 dividends of U.S. $0.09625 per common share. Based on the Bank of Canada noon exchange rate on the declaration date, the Canadian dollar equivalent for the fourth quarter 2015 dividends is set at Cdn $0.12673 per common share.

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

	Q1 2015	Q2 2015	Q3 2015	Q4 2015	Annual
U.S. dollar Dividend	0.08750	0.09625	0.09625	0.09625	0.37625
Canadian dollar equivalent	0.11098	0.12006	0.12892	0.12673	0.48669

2015 Generation Group Highlights

Deerfield Wind Project Joint Venture

On October 19, 2015 the Generation Group announced it has agreed to jointly develop a 150 MW construction stage wind project in the United States with Renewable Energy Systems Americas Inc.

The Deerfield Wind Project is located in central Michigan and is being constructed on approximately 20,000 acres of land leased from a supportive wind power land owner group. The project will utilize 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs annually. The project has a 20 year power purchase agreement with a local electric distribution utility serving approximately 260,000 customers in Michigan.

The total project cost is expected to be approximately U.S. $303.0 million. The project is expected to achieve commercial operation at the end of 2016 with its first full year of operation being 2017.

Letter of Credit Facility

On October 30, 2015, the Generation Group entered into a new extendible one year letter of credit facility ("Generation LC Facility") agreement. The new facility expands the group's available liquidity by providing for issuances of letters of credit up to a maximum based on two separate tranches of Cdn $50.0 million and U.S. $30.0 million. Upon closing certain letters of credit issued on the existing Generation Credit Facility were transferred to the new facility.

2015 Distribution Group Highlights

U.S. Debt Private Placement

On July 15, 2015, the Distribution Group issued U.S. $70.0 million notes representing the second of two tranches in the U.S. $160.0 million senior unsecured 30 year private placement notes bearing a coupon of 4.13% entered into on April 30, 2015. The first tranche of U.S. $90.0 million notes were issued upon closing of the private placement on April 30th. The proceeds of the financing will be used to partially finance the acquisition of the Park Water System and for general corporate purposes. The notes have been assigned a rating of BBB High by DBRS.

The financing is the fourth series of notes issued pursuant to the company's master indenture.

2015 Third Quarter Results From Operations

Key Selected Third Quarter Financial Information

(all dollar amounts in $ millions except per share information)	Three months ended September 30, 2015	2014
Revenue	**$ 189.6**	$ 151.6
Adjusted EBITDA[1]	**70.2**	41.4
Cash provided by/(used) operating activities	**76.2**	(3.1)
Adjusted funds from operations[1]	**54.3**	18.7
Net earnings/(loss) attributable to shareholders from continuing operations	**16.7**	(6.1)
Net earnings/(loss) attributable to shareholders	**16.5**	(6.3)
Adjusted net earnings/(loss)[1]	**17.3**	(0.4)
Dividends declared to common shareholders	**32.6**	22.3
Weighted Average number of common shares outstanding[3]	**252,352,179**	210,791,056
Per share		
Basic net earnings/(loss) from continuing operations	**$ 0.06**	$ (0.04)
Basic net earnings/(loss)	**$ 0.05**	$ (0.04)
Adjusted net earnings/(loss)[1, 2]	**$ 0.06**	$ (0.01)
Diluted net earnings/(loss)	**$ 0.05**	$ (0.04)
Cash provided by/(used) operating activities [1,2]	**$ 0.32**	$ (0.01)
Adjusted funds from operations[1, 2]	**$ 0.22**	$ 0.08
Dividends declared to common shareholders	**$ 0.13**	$ 0.10

1 Non-GAAP Financial Measures

2 APUC uses per share adjusted net earnings, cash provided by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.

3 Inclusive of subscription receipts not yet converted to common shares

For the three months ended September 30, 2015, APUC experienced an average U.S. exchange rate of approximately 1.3091 as compared to 1.0892 in the same period in 2014. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the three months ended September 30, 2015, APUC reported total revenue of $189.6 million as compared to $151.6 million during the same period in 2014, an increase of $38.0 million. The major factors resulting in the increase in APUC revenue in the three months ended September 30, 2015 as compared to the corresponding period in 2014 are set out as follows:

(all dollar amounts in $ millions)		Three months ended September 30, 2015
Comparative Prior Period Revenue	$	151.6
Significant Changes:		
Increased wind resources at the Minonk, Senate and Shady Oaks Wind Facilities partially offset by decreased wind resources at the Sandy Ridge Wind Facility.		3.1
Start of commercial operations of the St. Damase (Q4'14) and Morse (Q2'15) Wind Facilities.		3.5
Start of commercial operations at the Bakersfield I Solar Facility (Q2'15).		1.3
Decreased hydrological resources in the Ontario, Western and Maritime regions, in addition to decreased customer load and retail pricing in the Maritime region; partially offset by increased production in the Quebec region.		(2.9)
Lower cost of gas (which is a direct pass-through to customers) at the Windsor Locks and Sanger Thermal Facilities.		(0.8)
Decrease in Natural Gas Distribution Systems revenues due to lower commodity cost which are a direct pass-through to customers and decreased usage at the Midstates Gas, EnergyNorth Gas, and Peach State Gas Systems.		(9.2)
Increase in sales of Renewable Energy Credits as a result of increased production at US wind facilities.		0.4
Increased revenue due to rate case impacts at the Pine Bluff Water, LPSCo Water, EnergyNorth Gas, Peach State Gas, Illinois Gas, and Missouri Gas Systems.		4.0
Increase in revenue due to the acquisitions of the White Hall Water & Waste System (Q2'14) and the New Hampshire Gas System (Q1'15).		0.6
Increase in revenue for contracted services.		8.4
Increased demand for natural gas transportation.		0.9
Impact of the stronger U.S. dollar.		29.3
Other		(0.6)
Current Period Revenue	$	189.6

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

Adjusted EBITDA in the three months ended September 30, 2015 totalled $70.2 million as compared to $41.4 million during the same period in 2014, an increase of $28.8 million. The increase in Adjusted EBITDA was primarily due to impact of rate case settlements, full three months production of the Morse Wind Facility and Bakersfield I Solar Facility, and a stronger U.S. Dollar. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings section (See Non-GAAP Performance Measures).

For the three months ended September 30, 2015, net earnings attributable to Shareholders from continued operations totalled $16.7 million as compared to a loss of $6.1 million during the same period. The increase was due to $26.0 million in increased earnings from operating facilities, $1.1 million in increased foreign currency gains, $0.5 million in decreased interest expense, $0.7 million in increased interest and dividend income, $0.6 million increase in other gains, $5.7 million in decreased property plant and equipment write-downs, and $2.2 million in reduced allocation of earnings to non-controlling interests as compared to the same period in 2014. These items were partially offset by $4.1 million in increased depreciation and amortization expenses, $0.3 million in increased administration charges, $0.2 million in increased acquisition costs, $1.9 million in decreased gains from derivative instruments, and $7.6 million increase in income tax expense (tax explanations are discussed in APUC: *Corporate and Other Expenses).*

For the three months ended September 30, 2015, net earnings (including discontinued operations) attributable to Shareholders totalled $16.5 million as compared to a loss attributable to Shareholders of $6.3 million during the same period in 2014. Net earnings per share totalled $0.05 for the three months ended September 30, 2015, as compared to net loss per share of $0.04 during the same period in 2014.

During the three months ended September 30, 2015, cash provided by operating activities totalled $76.2 million or $0.32 per share as compared to cash used by operating activities of $3.1 million, or $0.01 per share during the same period in 2014. During the three months ended September 30, 2015, adjusted funds from operations totalled $54.3 million or $0.22 per share as compared to adjusted funds from operations of $18.7 million, or $0.08 per share during the same period in 2014. The change in adjusted funds from operations in the three months ended September 30, 2015, is primarily due to increased earnings from operations, as compared to the same period in 2014.

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

2015 Nine Month Results From Operations

Key Selected Nine Months Financial Information

(all dollar amounts in $ millions except per share information)	Nine months ended September 30, 2015		Nine months ended September 30, 2014	
Revenue	**$**	**767.6**	$	682.3
Adjusted EBITDA [1]		**266.0**		206.1
Cash provided by operating activities		**167.5**		96.3
Adjusted funds from operations[1]		**210.3**		140.6
Net earnings attributable to shareholders from continuing operations		**80.5**		44.7
Net earnings attributable to shareholders		**79.5**		44.1
Adjusted net earnings [1]		**82.0**		53.0
Dividends declared to common shareholders		**90.8**		57.5
Weighted Average number of common shares outstanding[4]		**251,528,726**		208,322,421
Per share				
Basic net earnings from continuing operations	**$**	**0.29**	$	0.18
Basic net earnings	**$**	**0.29**	$	0.18
Adjusted net earnings [1, 2]	**$**	**0.31**	$	0.22
Diluted net earnings	**$**	**0.28**	$	0.18
Cash provided by operating activities [1, 2]	**$**	**0.70**	$	0.47
Adjusted funds from operations[1, 2]	**$**	**0.85**	$	0.65
Dividends declared to common shareholders	**$**	**0.36**	$	0.27
Total assets		**4,759.0**		3,799.3
Long term liabilities [3]		**1,613.3**		1,404.3

1 Non-GAAP Financial Measure (See "Non-GAAP Financial Measures for further detail").

2 APUC uses per share adjusted net earnings, cash provided/(used) by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.

3 Includes long-term liabilities and current portion of long-term liabilities.

4 Inclusive of subscription receipts not yet converted to common shares.

For the nine months ended September 30, 2015, APUC experienced an average U.S. exchange rate of approximately $1.2598 as compared to $1.0944 in the same period in 2014. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's Canadian dollar reporting currency.

For the nine months ended September 30, 2015, APUC reported total revenue of $767.6 million as compared to $682.3 million during the same period in 2014, an increase of $85.3 million or 13%. The major factors resulting in the increase in APUC revenue for the nine months ended September 30, 2015, as compared to the corresponding period in 2014 are set out as follows:

(all dollar amounts in $ millions)		Nine months ended September 30, 2015
Comparative Prior Period Revenue	$	682.3
Significant Changes:		
Decreased wind resources at all facilities other than the Sandy Ridge Wind Facility offset by unfavorable settlements in the prior year on periodic production shortfalls under power hedges at the Minonk, Senate and Sandy Ridge Wind Facilities.		1.8
Start of commercial operations of the St. Damase (Q4'14) and Morse (Q2'15) Wind Facilities.		9.2
Start of commercial operations at the Cornwall (Q1'14) and Bakersfield I (Q2'15) Solar Facilities.		3.3
Decreased hydrological resources in the Western Region, decreased customer load and retail pricing in the Maritime Region, partially offset by increased production in the Quebec Region.		(8.3)
Higher realized prices from Renewable Energy Credits partially offset by lower production from the U.S. Wind facilities.		1.6
Lower cost of gas (which is a direct pass-through to customers) at the Windsor Locks and Sanger Thermal Facilities.		(6.5)
Decrease in Natural Gas Distribution Systems revenues due to lower commodity cost which are a direct pass-through to customers and decreased customer demand.		(36.7)
Increased revenue due to rate case impacts at the Pine Bluff Water, LPSCo Water, EnergyNorth Gas, Peach State Gas, Illinois Gas, and Missouri Gas Systems.		16.1
Increase in revenue due to the acquisitions of the White Hall Water & Waste System (Q2'14) and the New Hampshire Gas System (Q1'15).		4.1
Increased demand for natural gas transportation.		4.0
Increased revenues for contracted services.		10.0
Impact of the stronger U.S. dollar.		87.1
Other		(0.4)
Current Period Revenue	$	767.6

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

Adjusted EBITDA in the nine months ended September 30, 2015 totalled $266.0 million as compared to $206.1 million during the same period in 2014, an increase of $59.9 million. The increase in Adjusted EBITDA was primarily due to impact of rate case settlements, full nine months production of the St. Damase Wind Facility and Cornwall Solar Facility, along with the start of production of the Morse Wind Facility and Bakersfield I Solar Facility, and a stronger U.S. dollar. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings section. (See Non-GAAP Performance Measures).

For the nine months ended September 30, 2015, net earnings from continuing operations attributable to Shareholders totalled $80.5 million as compared to $44.7 million during the same period in 2014, an increase of $35.8 million. The increase was due to $62.8 million in increased earnings from operating facilities, $1.5 million in increased foreign currency gains, $3.0 million increase in other gains, $6.1 million in decreased property plant and equipment write-downs, $1.6 million in increased gain from derivative instruments, and $6.2 million decreased allocations of earnings to non-controlling interests as compared to the same period in 2014. These items were partially offset by $22.8 million in increased depreciation and amortization expenses, $3.3 million in increased administration charges, $0.3 million in increased interest expense, $0.4 million increase in acquisition costs, and $18.8 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses),* as compared to the same period in 2014.

For the nine months ended September 30, 2015, net earnings (including discontinued operations) attributable to Shareholders totalled $79.5 million as compared to $44.1 million during the same period in 2014, an increase of $35.4 million. Net earnings per share totalled $0.29 for the nine months ended September 30, 2015, as compared to $0.18 during the same period in 2014.

During the nine months ended September 30, 2015, cash provided by operating activities totalled $167.5 million or $0.70 per share as compared to cash provided by operating activities of $96.3 million, or $0.47 per share during the same period in 2014. During the nine months ended September 30, 2015, adjusted funds from operations, a non-GAAP measure, totalled $210.3 million or $0.85 per share as compared to adjusted funds from operations of $140.6 million, or $0.65 per share during the same period in 2014, an increase of $69.7 million.

Cash per share provided/used by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided/used by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided/used by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

Generation Business Group

Renewable Energy Division

	Long Term Average Resource	Three months ended September 30,		Long Term Average Resource	Nine months ended September 30,	
		2015	**2014**		**2015**	**2014**
Performance (GW-hrs sold)						
Hydro Facilities:						
Maritime Region	**24.1**	**20.5**	22.0	**132.0**	**101.4**	109.4
Quebec Region[1]	**62.3**	**61.6**	57.5	**202.1**	**188.1**	187.1
Ontario Region	**31.7**	**30.5**	33.6	**106.0**	**106.4**	105.8
Western Region	**23.8**	**19.7**	27.0	**52.4**	**42.6**	60.8
	141.9	**132.3**	140.1	**492.5**	**438.5**	463.1
Wind Facilities:						
Morse[2]	**22.6**	**18.2**	—	**43.4**	**37.3**	—
Red Lily[3]	**19.9**	**17.4**	16.0	**63.9**	**58.1**	63.9
St. Damase[4]	**16.3**	**16.2**	—	**55.7**	**52.7**	—
St. Leon	**85.6**	**84.9**	82.6	**306.5**	**302.6**	321.5
Sandy Ridge	**29.9**	**20.3**	22.5	**114.7**	**106.3**	102.3
Minonk	**107.6**	**91.7**	89.1	**468.7**	**424.7**	453.1
Senate	**91.7**	**103.7**	92.8	**380.4**	**332.9**	398.6
Shady Oaks	**53.2**	**51.6**	46.2	**259.3**	**228.1**	247.7
	426.8	**404.0**	349.2	**1,692.6**	**1,542.7**	1,587.1
Solar Facilities:						
Cornwall	**4.6**	**5.1**	5.2	**12.7**	**12.9**	10.5
Bakersfield I[5]	**21.7**	**11.8**	—	**39.7**	**13.4**	—
	26.3	**16.9**	5.2	**52.4**	**26.3**	10.5
Total Performance	**595.0**	**553.2**	**494.5**	**2,237.5**	**2,007.5**	**2,060.7**

1 The Generation Group's Donnacona Hydro Facility was offline in 2015. Insurance proceeds were received to compensate for a portion of lost revenue.

2 The Morse Wind Facility achieved commercial operation on April 22, 2015.

3 APUC does not consolidate the operating results from this facility in its financial statements. Production from the facility is included as APUC manages the facility under contract and has an option to acquire a 75% equity interest in the facility in 2016.

4 The St Damase Wind Facility achieved commercial operation on December 2, 2014.

5 The Bakersfield I Solar Facility achieved COD in accordance with the provisions of the PPA on April 14, 2015.

(all dollar amounts in $ millions)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Revenue[1]				
Hydro	**$ 11.4**	$ 13.8	**$ 41.1**	$ 48.2
Wind	**22.7**	13.7	**79.6**	61.9
Solar	**4.0**	2.4	**8.6**	4.8
Total Revenue	**$ 38.1**	$ 29.9	**$ 129.3**	$ 114.9
Less:				
Cost of Sales - Energy[2]	**(1.5)**	(2.8)	**(8.6)**	(15.1)
Realized gain on hedges[3]	**—**	(0.2)	**0.6**	3.8
Net Energy Sales	**$ 36.6**	$ 26.9	**$ 121.3**	$ 103.6
Renewable Energy Credits ("REC")[4]	**2.4**	1.3	**11.4**	7.9
Other Revenue	**0.3**	0.2	**0.9**	1.0
Total Net Revenue	**$ 39.3**	$ 28.4	**$ 133.6**	$ 112.5
Expenses & Other Income				
Operating expenses	**(14.4)**	(12.1)	**(40.3)**	(35.1)
Interest and Other income	**0.4**	0.5	**1.3**	1.3
HLBV income	**4.5**	2.3	**21.4**	18.3
Divisional operating profit	**$ 29.8**	$ 19.1	**$ 116.0**	$ 97.0

1 While most of the Generation Group's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that earn lower energy rates can result in a lower 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 supplement the energy sales from the Tinker Facility which is sold to retail and industrial customers under multi-year contracts.

3 See financial statements note 20(b)(iv).

4 Qualifying U.S. based renewable energy projects receive RECs for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source. The RECs can be traded and the owner of the REC can claim to have purchases of renewable energy. REC revenue is recognized only at the time a generated REC unit is matched up with a previously signed REC sales contract with a third party. Generated REC units not immediately available to match against a signed contract are recorded as inventory with the offset recorded as a decrease in operating expenses.

2015 Third Quarter Operating Results

For the three months ended September 30, 2015, the hydro facilities generated 132.3 GW-hrs of electricity, as compared to 140.1 GW-hrs produced in the same period in 2014, a decrease of 6%. The decreased generation is largely attributable to lower hydrology in the Western Region which were impacted most of the year by poor winter snowpack resulting in reduced summer water flows.

During the three months ended September 30, 2015, the hydro facilities generated electricity equal to 93% of long-term average resource ("LTAR") as compared to 97% during the same period in 2014. During the three months ended September 30, 2015, the Ontario Region achieved production slightly below its long-term average. The Quebec Region was below the long term average due to Donnacona being offline; excluding Donnacona, the Quebec Region achieved 108% of the long-term average resources. The Maritime Region was below its LTAR due to below average flows. The Western Region was below its LTAR due to flow restrictions imposed by Alberta Energy at Dickson Dam related to low water levels in the area.

For the three months ended September 30, 2015, revenue from the hydro facilities totalled $11.4 million as compared to $13.8 million during the same period in 2014, a decrease of $2.4 million. Lower revenues were recorded due to lower production in the Ontario, Maritime and Western Regions, and lower customer load in the Maritime Region.

For the three months ended September 30, 2015, energy purchase costs at the Maritime Region totalled $1.5 million, as compared to $2.8 million during the same period in 2014, a decrease of $1.3 million. The decrease in the energy purchase costs for the three months ended September 30, 2015 were primarily due to decreased retail customer load served requiring reduced energy purchases from the market.

During the three months ended September 30, 2015, the Maritime Region generated approximately 50% of the load required to service its customers, as compared to 25% in the same period in 2014. In an effort to minimize the risk of exposure to higher average energy prices, certain power derivative instruments are entered into as part of risk mitigation strategies. For the three months ended September 30, 2015, no realized derivative gains and losses were recorded as compared to a loss of $0.2 million, in the same period in 2014. Net energy sales at the Maritime region totalled $2.1 million for three months ended September 30, 2015 as compared to $2.4 million in the same quarter in the prior year a decrease of $0.3 million.

For the three months ended September 30, 2015, the wind facilities produced 404.0 GW-hrs of electricity, as compared to 349.2 GW-hrs produced in the same period in 2014, an increase of 15.7%. The increased production level is largely attributed to both increased wind resources as well as the St. Damase and Morse Wind Facilities achieving commercial operation in December 2014 and April 2015, respectively.

During the three months ended September 30, 2015, the wind facilities (excluding the St. Damase and Morse Wind Facilities) generated electricity equal to 95% of LTAR, as compared to 90% during the same period in 2014, due to the better wind resource in the quarter.

For the three months ended September 30, 2015, revenue from the wind facilities totalled $22.7 million as compared to $13.7 million during the same period in 2014, an increase of $9.0 million. The increase in revenue was primarily attributable to the new Morse and St. Damase Wind Facilities, increases in production, and a higher average U.S. dollar exchange rate.

For the three months ended September 30, 2015, REC revenue totalled $2.4 million, as compared to $1.3 million in the same period in 2014, an increase of $1.1 million. The increase in REC revenue was a result of increased production, increased pricing in the PJM region and a stronger U.S. dollar. The increase in REC pricing is, in part, due to increasing renewable requirement of the Renewable Portfolio Standards in several U.S. states. REC units are generated at a ratio of one REC unit per one MW-hr generated and are sold in the market in which the REC is generated. For the three months ended September 30, 2015, REC units and related revenues were generated at the Sandy Ridge, Minonk and Senate Wind Facilities.

During the three months ended September 30, 2015, the Generation Group's solar facilities generated 16.9 GW-hrs of electricity, as compared to 5.2 GW-hrs of electricity produced in the same period in 2014. The increase in production is attributable to the new Bakersfield I Solar Facility which achieved commercial operation ("COD") in accordance with the provisions of the PPA on April 14, 2015.

Cornwall's production was equal to 111% of its LTAR, as compared to 113% in the same period last year. Bakersfield I Solar Facility achieved 54% of its LTAR due to an equipment malfunction which damaged the inverter houses impacting 30% of the facility. Repairs are ongoing and is expected to be completed in the fourth quarter of 2015.

Revenue from generation at the Generation Group’s solar facilities totalled $4.0 million for the period as compared to $2.4 million in the same period of 2014 due to the increased quantity of power generated.

For the three months ended September 30, 2015, operating expenses excluding energy purchases totalled $14.4 million, as compared to $12.1 million during the same period in 2014, an increase of $2.3 million. The increase was primarily attributable to operating costs at the Morse and St. Damase Wind Facility which reached commercial operations in Q2 2015 and Q4 2014 respectively and the appreciation of the U.S. dollar.

The Red Lily I Wind Facility located in Saskatchewan produced 17.4 GW-hrs of electricity for the three months ended September 30, 2015. The Generation Group's economic return from its investment in the Red Lily I Wind Facility currently comes in the form of interest payments, fees and other charges and is not reflected in revenue from energy sales. Under the terms of the agreements, the Generation Group has the right to exchange these contractual and debt interests in the Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the three months ended September 30, 2015, the Generation Group earned fees of $0.3 million which was consistent with the same period in 2014 and is classified as other revenue.

For the three months ended September 30, 2015, interest and other income totalled $0.4 million as compared to $0.5 million during the same period in 2014. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in the Red Lily I Wind Facility. This amount is included as part of the Generation Group’s earnings from its investment in the Red Lily I Wind Facility, as discussed above.

For the three months ended September 30, 2015, the value of net tax attributes generated Hypothetical Liquidation at Book Value ("HLBV") income of $4.5 million, as compared to $2.3 million during the same period in 2014, an increase of $2.2 million compared to the prior period. The increase is primarily from $0.9 million of HLBV income from the Bakersfield I Solar Facility (which was placed in service on December 30, 2014), increased production at US Wind sites, a stronger U.S. dollar, and reduced economic interest of Tax Equity investors in the projects. HLBV income represents the value of net tax attributes generated by the Generation Group in the period from certain of its U.S. wind and solar powered generation facilities.

For the three months ended September 30, 2015, the Renewable Energy Division’s operating profit totalled $29.8 million, as compared to $19.1 million during the same period in 2014, an increase of $10.7 million; $1.8 million of the increase in attributable to the stronger U.S. dollar.

2015 Nine Month Operating Results

For the nine months ended September 30, 2015, the hydro facilities generated 438.5 GW-hrs of electricity, as compared to 463.1 GW-hrs produced in the same period in 2014, a decrease of 5%. The decrease in generation is due to the Donnacona Hydro Facility in Quebec being offline and lower production in the Western Region due to water flow restrictions, partially offset by increased hydrological resources at the Maritime Region and the other Quebec Region hydro facilities.

During the nine months ended September 30, 2015, the hydro facilities generated electricity equal to 89% of LTAR, as compared to 94% during the same period in 2014. The Quebec Region achieved 93% of its long term average primarily as a result of the Donnacona Hydro Facility being offline during the year; excluding the Donnacona Hydro Facility, the Quebec region achieved 101% of its long term average.

For the nine months ended September 30, 2015, revenue from the hydro facilities totalled $41.1 million, as compared to $48.2 million during the same period in 2014, a decrease of $7.1 million. Revenue from generation in the Ontario Region increased by $0.5 million due to increased rates over the prior year, while the Western Region experienced a decrease of $1.2 million which was the result of lower production as compared to the same period in the prior year. Revenue in the Quebec Region was approximately the same as compared to the previous period. Lost revenues from Donnaconna being offline have been made up by business interruption insurance proceeds as compared to the prior year. Revenue from the Maritime Region decreased $6.0 million, primarily due to decreased retail customer load served.

For the nine months ended September 30, 2015, energy purchases related to the Maritime Region totalled $8.6 million, as compared to $15.1 million during the same period in 2014, a decrease of $6.5 million. The decrease in energy purchases for the nine months ended September 30, 2015 was a result of the lower retail customer load which decreased the overall energy purchase requirement and drove an increase in the percentage of power which was supplied by owned assets. In addition, the average nine months ended September 30, 2015 energy purchase price was significantly lower than that of the prior year due to the abnormally high prices in the first quarter of 2014.

During the nine months ended September 30, 2015, the Maritime Region generated approximately 55% of the load required to service its customers, as compared to 39% in the same period in 2014. To mitigate the risk of higher average energy prices, the Maritime Region had previously entered into certain power hedges as part of its risk mitigation strategies. For the nine months ended September 30, 2015, $0.6 million was realized in connection with these hedges and is recorded as a realized gain on derivative financial instruments on the unaudited interim consolidated statement of operations. Net energy sales at the Maritime region totalled $6.7 million for nine months ended September 30, 2015 as compared to $9.4 million in the prior year a decrease of $2.7 million.

For the nine months ended September 30, 2015, the wind facilities produced 1,542.7 GW-hrs of electricity, as compared to 1,587.1 GW-hrs produced in the same period in 2014, a decrease of 3%. The decreased generation was a result of weaker wind resources earlier in 2015 at all facilities except the Sandy Ridge Wind Facility partially offset by production at the new Morse and St. Damase Wind Facilities.

During the nine months ended September 30, 2015, the wind facilities generated electricity equal to 91% of long-term average resources, as compared to 100% during the same period in 2014. For the nine months ended September 30, 2015, revenue from the wind facilities totalled $79.6 million, as compared to $61.9 million during the same period in 2014, an increase of $17.7 million. Revenue from the Generation Group's Canadian wind facilities increased $8.3 million largely due to the addition of the Morse and St. Damase Wind Facilities which offset the weaker production at the existing facilities. Revenue from the U.S wind facilities increased $9.4 million largely from higher pricing realized on sales of the unhedged portion of energy produced and a higher average U.S. dollar exchange rate. These favorable variances were partially offset by lower production at all facilities other than the Sandy Ridge Wind Facility.

For the nine months ended September 30, 2015, REC revenue totalled $11.4 million, as compared to $7.9 million in the same period in 2014, an increase of $3.5 million. The increase is primarily a result of a stronger U.S. exchange rate and higher prices of RECs for the three sites in the PJM market (Minonk, Sandy Ridge and Shady Oaks Wind Facilities). The increases were partially offset by lower volume of RECs sold due to lower production.

During the nine months ended September 30, 2015, the Generation Group's solar facilities generated 26.3 GW-hrs of electricity, as compared to 10.5 GW-hrs of electricity produced in the same period in 2014. The increase in production is attributable to the new Bakersfield I Solar Facility which achieved COD in accordance with the provisions of the PPA on April 14, 2015.

Cornwall's production was equal to 102% of its long-term average resources, as compared to 108% in the same period last year.

Revenue from generation at the Generation Group's solar facilities totalled $8.6 million for the period as compared to $4.8 million in the same period of 2014. The increase is attributed to the Cornwall Solar Facility which achieved commercial operation on March 27, 2014, and the new Bakersfield I Solar Facility.

For the nine months ended September 30, 2015, operating expenses excluding energy purchases totalled $40.3 million, as compared to $35.1 million during the same period in 2014, an increase of $5.2 million. The increase was primarily due to the appreciation of the U.S. dollar and additional operating costs incurred for the newly commissioned St. Damase and Morse Wind Facilities along with the new commissioned and Bakersfield I Solar Facility.

For the nine months ended September 30, 2015, interest and other income totalled $1.3 million which was consistent with the same period in 2014. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in the Red Lily I Wind Facility.

The Red Lily I Wind Facility located in Saskatchewan produced 58.1 GW-hrs of electricity for the nine months ended September 30, 2015. The Generation Group's economic return from its investment in the Red Lily I Wind Facility currently comes in the form of interest payments, fees and other charges and is not reflected in revenue from energy sales. Under the terms of the agreements, the Generation Group has the right to exchange these contractual and debt interests in the Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the nine months ended September 30, 2015, the Generation Group earned fees of $0.9 million (which is classified as other revenue) and interest income of $1.3 million from the Red Lily I Wind Facility.

For the nine months ended September 30, 2015, the value of net tax attributes generated amounted to HLBV income of $21.4 million, as compared to $18.3 million in the prior year. The increase is primarily a result of $2.8 million of HLBV income from the Bakersfield I Solar Facility (which was placed in service on December 30, 2014), a stronger U.S. dollar, and reduced economic interest of Tax Equity investors in the projects. These items were partially offset by decreased production at the U.S. wind facilities which in turn produced lower Production Tax Credits as compared to the prior year.

For the nine months ended September 30, 2015, the Renewable Energy Division's operating profit totalled $116.0 million, as compared to $97.0 million during the same period in 2014, an increase of $19.0 million; $7.9 million of the increase is attributable to the stronger U.S. dollar.

Thermal Energy Division

	Three Months ended September 30, 2015			Three Months ended September 30, 2014		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance (GW-hrs sold)	**30.7**	**36.6**	**67.3**	28.2	36.7	64.9
Performance (steam sales – billion lbs)	**121.1**	**—**	**121.1**	111.8	—	111.8
(all dollar amounts in $ millions)						
Revenue						
Energy/steam sales	**$ 4.4**	**$ 6.9**	**$ 11.3**	$ 3.5	$ 6.9	$ 10.4
Less:						
Cost of Sales – Fuel	**(2.1)**	**(1.6)**	**(3.7)**	(2.0)	(2.0)	(4.0)
Net Energy/Steam Sales	**$ 2.3**	**$ 5.3**	**$ 7.6**	$ 1.5	$ 4.9	$ 6.4
Other Revenue	**0.1**	**0.6**	**0.7**	0.4	0.5	0.9
Total Net Revenue	**$ 2.4**	**$ 5.9**	**$ 8.3**	$ 1.9	$ 5.4	$ 7.3
Expenses						
Operating Expenses	**(1.1)**	**(1.5)**	**$ (2.6)**	(1.0)	(1.2)	$ (2.2)
Facility operating profit	**$ 1.3**	**$ 4.4**	**$ 5.7**	$ 0.9	$ 4.2	$ 5.1
Interest and other income			**—**			(0.2)
Divisional operating profit			**$ 5.7**			$ 4.9

2015 Third Quarter Operating Results

The Generation Group's Sanger and Windsor Locks Thermal Facilities purchase natural gas from different suppliers and at prices based on different regional hubs. As a result, the average landed cost per unit of natural gas will differ between the two facilities in the average landed cost for natural gas and may result in the facilities showing differing costs per unit compared to each other and compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each MMBTU.

For the three months ended September 30, 2015, the Thermal Energy Division's operating profit was $5.7 million as compared to $4.9 million for the same period last year. Operating profit contributions for the three months ended September 30, 2015 were $1.3 million from the Windsor Locks Thermal Facility and $4.4 million from the Sanger Thermal Facility, as compared to $0.9 million and $4.2 million, respectively, during the same period in 2014. Interest and other income for the three months ended September 30, 2015 was nil, as compared to a loss of $0.2 million in the prior period. As a result of the stronger U.S. dollar, operating profit increased by $1.0 million.

Windsor Locks Thermal Facility

For the three months ended September 30, 2015, the Windsor Locks Thermal Facility sold 30.7 GW-hrs of electricity and 121.1 billion pounds of steam, as compared to 28.2 GW-hrs of electricity and 111.8 billion pounds of steam in the comparable period of 2014.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $4.4 million (U.S. $3.4 million), as compared to $3.5 million (U.S. $3.2 million) in the same period in 2014. The increase in electricity/steam sales is attributed to higher production partially offset by a lower average price for gas as cost of gas is a pass-through to customers. Gas costs for the period were $2.1 million (U.S. $1.6 million), as compared to $2.0 million (U.S. $1.8 million) in the same period in 2014. The change in gas costs is a result of decreases in the average landed cost of natural gas per MMBTU in the quarter, as compared to the same period in 2014.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy/steam sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended September 30, 2015, net sales at the Windsor Locks Thermal Facility totalled $2.3 million (U.S. $1.8 million) as compared to $1.5 million (U.S. $1.4 million) in the same period in 2014.

Operating expenses excluding fuel costs were $1.1 million (U.S. $0.8 million), as compared to $1.0 million (U.S. $0.9 million) in the same period in 2014. The increase was primarily due to the strengthening of the U.S. dollar as compared to the same period in 2014. The Windsor Locks Thermal Facility's resulting net operating income for the three months ended September 30, 2015 was $1.3 million as compared to $0.9 million in the prior period.

Sanger Thermal Facility

For the three months ended September 30, 2015, the Sanger Thermal Facility sold 36.6 GW-hrs of electricity, as compared to 36.7 GW-hrs of electricity in the comparable period of 2014.

For the three months ended September 30, 2015, the Sanger Thermal Facility's operating profit was driven by energy sales of $6.9 million (U.S. $5.4 million) as compared to $6.9 million (U.S. $6.4 million) in the same period in 2014. The decrease of U.S. $1.0 million in energy sales was primarily due to lower gas prices which are passed on to customers, as compared to the same period in 2014. Capacity revenues increased to $4.3 million as compared to $3.5 million in the same period in 2014, entirely due to the stronger U.S. exchange rate. Gas costs for the period were $1.6 million (U.S. $1.3 million), as compared to $2.0 million (U.S. $1.8 million) in the same period in 2014. The decrease in gas costs is largely due to a decrease in the average cost of natural gas per MMBTU, partly offset by a stronger U.S. dollar, as compared to the same period in 2014.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended September 30, 2015, net energy sales at the Sanger Thermal Facility totalled $5.3 million (U.S. $4.1 million), as compared to $4.9 million (U.S. $4.6 million) during the same period in 2014. The decrease in U.S. dollar net sales primarily results from a change in production mix between higher priced peak vs off-peak.

Operating expenses excluding natural gas costs were $1.5 million (U.S. $1.3 million), as compared to $1.2 million (U.S. $1.2 million) in the same period in 2014. The Sanger Thermal Facility's resulting net operating income for the three months ended September 30, 2015 was $4.4 million, as compared to $4.2 million during the same period in 2014.

Thermal Energy Division

	Nine months ended September 30, 2015			Nine months ended September 30, 2014		
	Windsor Locks	**Sanger**	**Total**	**Windsor Locks**	**Sanger**	**Total**
Performance(GW-hrs sold)	**88.2**	**97.4**	**185.6**	85.9	99.0	184.9
Performance(steam sales – billion lbs)	**458.0**	**—**	**458.0**	451.6	—	451.6
(all dollar amounts in $ millions)						
Revenue						
Energy/steam sales	**$ 16.0**	**$ 14.2**	**$ 30.2**	$ 18.3	$ 15.5	$ 33.8
Less:						
Cost of Sales – Fuel	**(9.7)**	**(4.3)**	**$ (14.0)**	(12.1)	(5.6)	(17.7)
Net Energy/Steam Sales	**$ 6.3**	**$ 9.9**	**$ 16.2**	$ 6.2	$ 9.9	$ 16.1
Other revenue	**1.2**	**1.7**	**2.9**	1.3	1.2	2.5
Total net revenue	**$ 7.5**	**$ 11.6**	**$ 19.1**	$ 7.5	$ 11.1	$ 18.6
Expenses						
Operating expenses	**(4.2)**	**(4.1)**	**(8.3)**	(3.8)	(3.6)	(7.4)
Facility operating profit	**$ 3.3**	**$ 7.5**	**$ 10.8**	$ 3.7	$ 7.5	$ 11.2
Interest and other income			**0.2**			(0.2)
Divisional operating profit			**$ 11.0**			$ 11.0

2015 Nine Month Operating Results

The Generation Group's Sanger and Windsor Locks Thermal Facilities purchase natural gas from different suppliers and at prices based on different regional hubs. As a result, the average landed cost per unit of natural gas will differ between the two facilities in the average landed cost for natural gas and may result in the facilities showing differing costs per unit compared to each other and compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each MMBTU.

For the nine months ended September 30, 2015, the Thermal Energy Division's operating profit was $11.0 million which is consistent with the same period in 2014. The Windsor Locks Thermal Facility contributed $3.3 million, while the Sanger Thermal Facility contributed $7.5 million of operating profit during the nine months ended September 30, 2015, as compared to $3.7 million and $7.5 million, respectively, during the same period in the prior year. Interest and other income for the nine months ended September 30, 2015 was $0.2 million as compared to a loss of $0.2 million during the same period in the prior year.

Windsor Locks Thermal Facility

For the nine months ended September 30, 2015, the Windsor Locks Thermal Facility sold 88.2 GW-hrs of energy and 458.0 billion pounds of steam, as compared to 85.9 GW-hrs of energy and 451.6 billion pounds of steam in the comparable period of 2014.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $16.0 million (U.S. $12.7 million), as compared to $18.3 million (U.S. $16.8 million) in the same period, a decrease of $2.3 million. The decrease in energy/steam sales is primarily due to lower prices and energy sales for electricity sold into the merchant market earlier in the year as compared to the same period in 2014. Gas costs for the period were $9.7 million (U.S. $7.8 million) as compared to $12.1 million (U.S. $11.0 million) in the same period in 2014, a decrease of $2.4 million. The decrease in gas costs is a result of lower average landed cost of natural gas per MMBTU in the first quarter of 2015 due to below seasonal temperatures in the first quarter of 2014, and lower volumes purchased due to decreased demand in 2015, as compared to the same period in 2014.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy/steam sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the nine months ended September 30, 2015, net energy/steam sales at the Windsor Locks Thermal Facility totalled $6.3 million which is consistent during the same period in 2014 in Canadian dollars. In U.S. dollars a decrease of U.S. $0.8 million was primarily due to the lower percentage sales to the merchant market due to the lower demand along with a decrease in steam sales as compared to the prior year as discussed above.

Operating expenses excluding natural gas costs were $4.2 million (U.S. $3.4 million), as compared to $3.8 million (U.S. $3.5 million) during the same period in 2014, an increase of $0.4 million primarily due to a stronger U.S. dollar exchange rate. The Windsor Locks Thermal Facility's resulting net operating income for the nine months ended September 30, 2015 was $3.3 million, as compared to $3.7 million in the same period in 2014, a decrease of $0.4 million.

Sanger Thermal Facility

For the nine months ended September 30, 2015, the Sanger Thermal Facility sold 97.4 GW-hrs of energy, as compared to 99.0 GW-hrs of energy in the comparable period of 2014.

For the nine months ended September 30, 2015, the Sanger Thermal Facility's operating profit was driven by energy/steam sales of $14.2 million (U.S. $11.3 million), as compared to $15.5 million (U.S. $14.1 million) in the same period in 2014, a decrease of $1.3 million. The decrease in energy sales is primarily attributable to decreased gas prices which are a pass through to customers as compared to 2014. Capacity revenue remained unchanged at $3.4 million. Gas costs for the period were $4.3 million (U.S. $3.4 million) as compared to $5.6 million (U.S. $5.1 million) in the same period in 2014, a decrease of $1.3 million. The decrease in gas costs is largely due to a 30% decrease in the average cost of natural gas per MMBTU, partially offset by a stronger U.S. dollar, as compared to the same period in 2014.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the nine months ended September 30, 2015, net energy sales at the Sanger Thermal Facility totalled $9.9 million (U.S. $7.9 million) which was consistent with the prior period based in Canadian dollars. Based in US dollars a decrease of $1.3 million was primarily a result of a decrease in gas prices and lower off peak generation during the quarter, as discussed above.

Operating expenses excluding natural gas costs were $4.1 million (U.S. $3.2 million), as compared to $3.6 million (U.S. $3.3 million) during the same period in 2014. The Sanger Thermal Facility's resulting net operating income for the nine months ended September 30, 2015 was $7.5 million which is consistent to the same period in 2014.

Generation Business Group

Development Division

The Development Division works to identify, develop and construct new power generating facilities, as well as to identify, and acquire, operating projects that would be complementary and accretive to the Generation Group's existing portfolio.

The Generation Group's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of PPAs. All of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with credit worthy counterparties, and meet or exceed the Company's investment return criteria.

Project Name	Location	Size (MW)	Estimated Capital Cost (millions)	Commercial Operation	PPA Term	Production GW-hrs
Projects in Construction						
Odell Wind Project[1]	Minnesota	200	$ 430.8	2016	20	814.7
Val-Éo Wind Project[2,3]	Quebec	24	$ 70.0	2016	20	66.0
Bakersfield II Solar Project[4]	California	10	$ 36.0	2016	20	24.2
Deerfield Wind Project[6]	Michigan	150	$ 404.4	2016	20	555.2
Total Projects in Construction		**384**	**$ 941.2**			**1,460.1**
Projects in Development						
Amherst Island Wind Project	Ontario	75	$ 272.5	2016/17	20	235.0
Chaplin Wind Project[5]	Saskatchewan	177	$ 340.0	2017/18	25	720.0
Total Projects in Development		**252**	**$ 612.5**			**955.0**
Total in Construction and Development		**636**	**$ 1,553.7**			**2,415.1**

1 Total cost of the project is expected to be approximately $322.8 million in U.S. dollars.

2 The Val-Éo Wind Project is being developed in two phases: Phase I of the project (24 MW) will be erected in 2016 and the 101 MW Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

3 Size, Estimated Capital Costs, Commercial Operation Date, PPA Term and Production refer solely to Phase I of the Val-Éo Wind Project.

4 Total cost of the project is expected to be approximately $27.0 million in U.S. dollars.

5 The Chaplin project is being developed in two phases: Phase I of the project, which comprises approximately 35 MW of the total project, will be erected in 2017 and Phase II of the project, which comprises the remaining approximately 142 MW, will be constructed following evaluation of the wind resource at the site, and completion of satisfactory permitting. Production estimate will vary with final turbine selection.

6 The total cost of the project is expected to be approximately $303.0 million in U.S. dollars.

Projects in Construction

Odell Wind Project

The 200MW Odell Wind Project is located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota. The Generation Group's interest in the project is via a 50% joint venture with the original developer. The Generation Group holds an option to acquire the other 50% interest of the project for total contributions, subject to certain adjustments, within 30 days of commencement of operations which is expected in 2016.

Construction of the project began in May 2015 and as of September 30, 2015 all 100 turbine foundations have been poured and back-filled. All new access roads and public road improvements are close to completion, while the new 115 kV transmission line is built. Approximately half of the collection system and substation work was complete as at September 30, 2015. The transmission provider has nearly completed carrying out work at the point of interconnection along with necessary network upgrades to facilitate energization of the transmission line. Vestas commenced turbine deliveries in later October, with pre-commissioning on track to start in mid-December, with the first turbine set to deliver test energy to the MISO grid in mid-January 2016.

Val-Éo Wind Project

The Val-Éo Wind Project is located in the local municipality of Saint -Gideon de Grandmont, Quebec and represents the first 24 MW phase of a 125 MW total development project.

As of July 2015, all land agreements, construction permits, and authorizations have been obtained. As the permitting process was delayed at the provincial level, construction planned in 2015 has been re-evaluated due to the severe weather conditions in the region. The new schedule calls for construction to begin early in the second quarter of 2016.

Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MW project adjacent to the Generation Group's 20 MW Bakersfield I Solar Project in Kern County, California.

During the third quarter the conditional use permit was approved by the county and grading, drainage, and substation building permits were issued. The Generation Group has completed procurement of long lead electrical equipment including modules, and the engineering and design of the facility is nearing completion. Construction of the project substation has commenced with construction of the solar project scheduled to begin in the fourth quarter of 2016.

Deerfield Wind Project

The Deerfield Wind Project ("Deerfield") is located in central Michigan and is being constructed on approximately 20,000 acres of land leased from a supportive wind power land owner group. The Generation Group's interest in the project is via a 50% joint venture with the original developer. The Generation Group holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments within 90 days of commencement of operations.

Construction of the project has begun with 50% of the private land access roads constructed and improvements to public roads to facilitate turbine component delivery has commenced. The project will utilize 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs annually. Four turbine foundations have begun construction with 26 slated for completion in Q4 2015. The main power transformer procurement has been finalized and engineering for the project is nearing completion. Deerfield has a 20 year power purchase agreement with a local electric distribution utility serving approximately 260,000 customers in Michigan.

The total project cost is expected to be approximately U.S. $303 million. The project is expected to achieve commercial operation at the end of 2016 with its first full year of operation beginning 2017.

Projects in Development

Amherst Island Wind Project

The 75MW Amherst Island Wind Project is located on Amherst Island near the village of Stella, approximately 15 km southwest of Kingston, Ontario.

The Renewable Energy Approval (“REA”) was issued on August 24, 2015 following 29 months of review by the Ontario Ministry of Environment.

An appeal of the REA has been made to the Environmental Review Tribunal (“ERT”), the appeal process is expected to take up to 6 months and conclude no later than March 8, 2016. Other permitting processes, and the engineering and procurement of long-lead equipment are progressing according to schedule including the supply of turbines for the project. The project has a planned construction time frame of 12 to 18 months with most of the construction expected to occur in 2016. The project team is preparing to begin construction on the docks in fourth quarter of 2015, which will support transport of equipment, materials, and personnel during construction. The submarine cable which is a key portion of the interconnection infrastructure that will be installed linking the island to the mainland has been procured.

Chaplin Wind Project

The 177MW Chaplin Wind Project is located in the rural municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

In the first quarter of 2015, the Environmental Assessment documentation was submitted and meetings were held with the Ministry of Environment ("SKMOE"). Supplemental reports were submitted in the second and third quarters of 2015. The SKMOE is currently preparing the package for the 30 day public posting period. The turbine and balance of plant contractor selection will be finalized upon signing of the turbine supply agreement, which is dependent on the SMKOE permit approval.

Distribution Business Group

The Distribution Group operates rate-regulated utilities providing distribution services to approximately 488,000 connections in the natural gas, electric, water and wastewater sectors. The Distribution Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Distribution Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

Utility System Type	September 30, 2015			September 30, 2014		
(all dollar amounts in U.S. $ millions)		Assets	Connections		Assets	Connections
Electricity	$	**338.1**	**93,000**	$	306.8	93,000
Natural Gas		**763.2**	**292,000**		697.8	292,000
Water and Wastewater		**255.8**	**103,000**		242.2	103,000
Total	$	**1,357.1**	**488,000**	$	1,246.8	488,000
Accumulated Deferred Income Taxes	$	**100.9**		$	91.8	

The Distribution 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 93,000 connections in the states of California and New Hampshire.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 292,000 connections located in the states of New Hampshire, Illinois, Iowa, Missouri, Georgia, and Massachusetts.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 103,000 connections located in the states of Arkansas, Arizona, Texas, Illinois, and Missouri. The Distribution Group has entered into an agreement to acquire Park Water Company ("Park Water System") which owns and operates three regulated water utilities serving approximately 74,000 customer connections in Southern California and Western Montana.

	Three months ended September 30,				Three months ended September 30,			
		2015 U.S. $ (millions)		2014 U.S. $ (millions)		**2015 Can $ (millions)**		2014 Can $ (millions)
Revenue								
Utility electricity sales and distribution	$	**40.8**		44.6	$	**53.4**		48.6
Less: Cost of Sales – Electricity		**(22.4)**		(25.2)		**(29.3)**		(27.4)
Net Utility Sales - Electricity	$	**18.4**	$	19.4	$	**24.1**	$	21.2
Utility natural gas sales and distribution		**34.2**		36.1		**44.6**		39.3
Less: Cost of Sales – Natural Gas		**(7.4)**		(12.6)		**(10.0)**		(13.8)
Net Utility Sales - Natural Gas	$	**26.8**	$	23.5	$	**34.6**	$	25.5
Net Utility Sales - Water Distribution & Wastewater Treatment		**16.8**		15.8		**21.9**		17.2
Gas Transportation		**3.6**		2.8		**4.7**		2.9
Other Revenue		**9.1**		0.7		**12.1**		0.8
Net Utility Sales	$	**74.7**	$	62.2	$	**97.4**	$	67.6
Operating expenses		**(42.9)**		(40.3)		**(56.2)**		(43.5)
Other income		**0.8**		0.6		**1.0**		0.7
Distribution Group operating profit	$	**32.6**	$	22.5	$	**42.2**	$	24.8

2015 Third Quarter Operating Results

For the three months ended September 30, 2015, the Distribution Group reported an operating profit of U.S. $32.6 million, as compared to U.S. $22.5 million for the comparable period in the prior year. The increase is primarily due to the implementation of final rates at the EnergyNorth Gas System, the implementation of final rates as a result of the general rate case at the Missouri and Illinois Gas Systems, and contracted services. Detailed results are discussed in the following sections. Measured in Canadian dollars, the group's operating profit was $42.2 million, as compared to $24.8 million for the comparable period in the prior year. In addition to the factors described below, operating profit measured in Canadian dollars increased by $7.3 million due to a stronger U.S. dollar.

Electric Distribution Systems

	Three months ended September 30	
	2015	**2014**
Average Active Electric Connections For The Period		
Residential	**79,800**	79,200
Commercial and Industrial	**12,400**	12,100
Total Average Active Electric Connections For The Period	**92,200**	91,300
Customer Usage (GW-hrs)		
Residential	**132.2**	129.7
Commercial and Industrial	**237.5**	265.8
Total Customer Usage (GW-hrs)	**369.7**	395.5

For the three months ended September 30, 2015 the electric distribution systems' usage totalled 369.7 GW-hrs, as compared to 395.5 GW-hrs for the same period in 2014, a decrease of 25.8 GW-hrs.

For the three months ended September 30, 2015, the electric distribution systems' revenue from utility electricity sales totalled U.S. $40.8 million, as compared to U.S. $44.6 million during the same period in 2014, a decrease of U.S. $3.8 million, or 8.5%. For the three months ended September 30, 2015, fuel and purchased power costs for the electric distribution systems totalled U.S. $22.4 million, as compared to U.S. $25.2 million during the same period in 2014, a decrease of U.S. $2.8 million.

The purchase of electricity by the electric distribution systems is a significant revenue driver and component of operating expenses, however these costs are effectively passed through to its customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the three months ended September 30, 2015, net utility sales for the electric distribution systems were U.S. $18.4 million, as compared to U.S. $19.4 million during the same period in 2014, a decrease of U.S. $1.0 million, or 5% primarily due to the timing of a commodity cost adjustment applied in the same period in 2014.

Natural Gas Distribution Systems

	Three months ended September 30,	
	2015	**2014**
Average Active Natural Gas Connections For The Period		
Residential	**244,400**	243,500
Commercial and Industrial	**26,100**	26,300
Total Average Active Natural Gas Connections For The Period	**270,500**	269,800
Customer Usage (MMBTU)		
Residential	**986,000**	1,012,000
Commercial and Industrial	**1,402,000**	1,221,000
Total Customer Usage (MMBTU)	**2,388,000**	2,233,000

For the three months ended September 30, 2015, usage at the natural gas distribution systems totalled 2,388,000 MMBTU, as compared to 2,233,000 MMBTU during the same period in 2014, an increase of 155,000 MMBTU.

For the three months ended September 30, 2015, revenue excluding transportation revenue from natural gas sales and distribution totalled U.S. $34.2 million, as compared to U.S. $36.1 million during the same period in 2014, a decrease of U.S. $1.9 million. For the three months ended September 30, 2015, natural gas purchases totalled U.S. $7.4 million, as compared with U.S. $12.6 million for the same period in 2014, a decrease of U.S. $5.2 million. The cost of natural gas is passed through to the natural gas systems' customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the three months ended September 30, 2015, net utility sales for the natural gas distribution systems, excluding transportation, totalled U.S. $26.8 million, as compared to U.S. $23.5 million during the same period in 2014, an increase of U.S. $3.3 million. The increase in net utility sales, excluding transportation, can be primarily attributed to the implementation of final rates as a result of general rates cases at the EnergyNorth, Missouri, and Illinois Gas Systems.

For the three months ended September 30, 2015, revenue from gas transportation sales totalled U.S. $3.6 million, as compared to U.S. $2.8 million during the same period in 2014, an increase of U.S. $0.8 million. The increase in gas transportation sales can be primarily attributed to increased rates due to the completion of the rates cases.

Water and Wastewater Distribution Systems	Three months ended September 30,	
	2015	2014
Average Active Connections For The Period		
Wastewater connections	**40,000**	39,500
Water distribution connections	**58,700**	58,300
Total Average Active Connections For The Period	**98,700**	97,800
Gallons Provided (millions of gallons)		
Water sold (millions of gallons)	**2,478**	2,546
Wastewater treated (millions of gallons)	**497**	531
Total Gallons Provided (millions of gallons)	**2,975**	3,077

During the three months ended September 30, 2015, the water and wastewater distribution systems provided approximately 2,478 million gallons of water to its customers and treated approximately 497 million gallons of wastewater, as compared to 2,546 million gallons of water and 531 million gallons of wastewater during the same period in 2014. The decrease in water and waste consumption is primarily attributable to a wetter conditions in the Texas service area impacting the volumes of water and wastewater demand.

For the three months ended September 30, 2015, revenue from water and wastewater treatment distribution systems totalled U.S. $10.2 million and U.S. $6.6 million, respectively, as compared to U.S. $9.2 million and U.S. $6.6 million and respectively, during the same period in 2014. The increase in total wastewater treatment and water distribution system revenue was primarily due to an increase in volumes and rates at the Pine Bluff Water System.

Other Revenue

For the three months ended September 30, 2015, other revenue totalled U.S. $9.1 million, as compared to U.S. $0.7 million during the same period in 2014. The other revenue includes revenue earned from contracted services.

Operating Expenses

For the three months ended September 30, 2015, operating expenses, excluding commodity purchases, totalled U.S. $42.9 million, as compared to U.S. $40.3 million during the same period in 2014, an increase of U.S. $2.6 million. The major factors resulting in the increase in the Distribution Group's operating expenses in the three months ended September 30, 2015, as compared to the corresponding period in 2014, are set out as follows:

(all dollar amounts in U.S. $ millions)	Three months ended September 30, 2015
Comparative Prior Period Operating Expenses	40.3
Significant Changes:	
Increase in costs for contracted services	2.5
Acquisition of the New Hampshire Gas System	0.4
Other	(0.3)
Current Period Operating Expenses	42.9

The increase in operating expenses can be primarily attributed to an increase in costs for contracted services performed, and the acquisition of the New Hampshire Gas System on January 2, 2015 which resulted in increased operating expense of U.S. $0.4 million for the three months ended September 30, 2015.

	Nine months ended September 30,		Nine months ended September 30,	
	2015 U.S. $ (millions)	2014 U.S. $ (millions)	**2015 Can $ (millions)**	2014 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 134.8**	137.3	**$ 169.5**	150.3
Less: Cost of Sales – Electricity	**(80.2)**	(78.9)	**(100.7)**	(86.3)
Net Utility Sales - Electricity	**$ 54.6**	$ 58.4	**$ 68.8**	$ 64.0
Utility natural gas sales and distribution	**259.5**	275.8	**323.6**	303.1
Less: Cost of Sales – Natural Gas	**(135.6)**	(169.3)	**(168.3)**	(186.2)
Net Utility Sales - Natural Gas	**$ 123.9**	$ 106.5	**$ 155.3**	$ 116.9
Net Utility Sales - Water Distribution & Wastewater Treatment	**46.0**	44.1	**58.1**	48.2
Gas Transportation	**20.7**	16.7	**25.9**	18.3
Other Revenue	**12.0**	2.0	**15.6**	2.2
Net Utility Sales	**$ 257.2**	$ 227.7	**$ 323.7**	$ 249.6
Operating expenses	**(128.9)**	(121.1)	**(162.4)**	(132.3)
Other income	**2.4**	2.1	**3.0**	2.5
Distribution Group operating profit	**$ 130.7**	$ 108.7	**$ 164.3**	$ 119.8

2015 Nine Month Operating Results

For the nine months ended September 30, 2015, the Distribution Group reported an operating profit of U.S. $130.7 million, as compared to U.S. $108.7 million for the comparable period in the prior year, an increase of U.S. $22.0 million or 20.2%. The increase is primarily due to the implementation of higher rates as a result of successful rate cases at the EnergyNorth, Missouri, Illinois, and Peach State Gas Systems, below seasonal temperatures experienced in the New Hampshire service territory, and revenues from contracted services as compared to the same period in 2014. Detailed results are discussed in the following sections. Measured in Canadian dollars, the group's operating profit was $164.3 million, as compared to $119.8 million for the comparable period in the prior year. In addition to the factors discussed below, operating profit measured in Canadian dollars increased by $22.5 million due to a stronger U.S. dollar.

Electric Distribution Systems

	Nine months ended September 30,	
	2015	**2014**
Average Active Electric Connections For The Period		
Residential	**79,800**	78,500
Commercial and Industrial	**12,400**	12,200
Total Average Active Electric Connections For The Period	**92,200**	90,700
Customer Usage (GW-hrs)		
Residential	**419.2**	422.5
Commercial and Industrial	**678.3**	703.0
Total Customer Usage (GW-hrs)	**1,097.5**	1,125.5

For the nine months ended September 30, 2015, the electric distribution systems' usage totalled 1,097.5 GW-hrs, as compared to 1,125.5 GW-hrs for the same period in 2014, a decrease of 28.0 GW-hrs.

For the nine months ended September 30, 2015, the electric distribution systems' revenue from utility electricity sales totalled U.S. $134.8 million, as compared to U.S. $137.3 million during the same period in 2014, a decrease of U.S. $2.5 million. For the nine months ended September 30, 2015, purchased power costs for the electric distribution systems totalled U.S $80.2 million, as compared to U.S. $78.9 million for the same period in 2014, an increase of U.S. $1.3 million.

The purchase of electricity by the electric distribution systems is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the nine months ended September 30, 2015, net utility sales for the electric distribution systems were U.S. $54.6 million, as compared to U.S. $58.4 million for the same period in 2014, a decrease of U.S. $3.8 million. Adjusting for the retroactive recognition of new revenues granted under Granite State Electric System rate case implemented in the first quarter of 2014 and timing of a commodity cost adjustment applied in the third quarter of 2014, revenues were consistent year over year.

Natural Gas Distribution Systems

	Nine months ended September 30,	
	2015	**2014**
Average Active Natural Gas Connections For The Period		
Residential	**248,500**	248,600
Commercial and Industrial	**26,700**	26,300
Total Average Active Natural Gas Connections For The Period	**275,200**	274,900
Customer Usage (MMBTU)		
Residential	**14,382,000**	14,996,000
Commercial and Industrial	**10,098,000**	9,788,000
Total Customer Usage (MMBTU)	**24,480,000**	24,784,000

For the nine months ended September 30, 2015, customer usage at the natural gas distribution systems totalled 24,480,000 MMBTU, as compared to 24,784,000 MMBTU during the same period in 2014, a decrease of 304,000 MMBTU.

For the nine months ended September 30, 2015, revenue from natural gas sales and distribution totalled U.S. $259.5 million, as compared to U.S. $275.8 million during the same period in 2014, a decrease of U.S. $16.3 million. For the nine months ended September 30, 2015, natural gas purchases totalled U.S. $135.6 million, as compared to U.S. $169.3 million for the same period in 2014, a decrease of U.S. $33.7 million. The cost of natural gas is passed through to the natural gas distribution systems' customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of results. For the nine months ended September 30, 2015, net utility sales, excluding transportation, for the natural gas distribution systems totalled U.S. $123.9 million, as compared to U.S. $106.5 million during the same period in 2014, an increase of U.S. $17.4 million. The increase in net utility sales, excluding transportation, can be primarily attributed to the implementation of final rates at the EnergyNorth and the Missouri and Illinois Gas Systems along with a one-time adjustment of U.S. $3.0 million to true up the interim rates initially granted at EnergyNorth retroactively to November 1, 2014.

For the nine months ended September 30, 2015, revenue from gas transportation sales totalled U.S. $20.7 million, as compared to U.S. $16.7 million during the same period in 2014, an increase of U.S. $4.0 million. The Midstates Gas System contributed U.S. $2.9 million, the EnergyNorth Gas System contributed U.S. $10.4 million, the Peach State Gas System contributed U.S. $2.0 million, and the New England Gas System contributed U.S. $5.4 million to the total transportation revenues for the period.

Water and Wastewater Distribution Systems

	Nine months ended September 30,	
	2015	**2014**
Average Active Connections For The Period		
Wastewater connections	**40,000**	38,500
Water distribution connections	**58,700**	57,200
Total Average Active Connections For The Period	**98,700**	95,700
Gallons Provided		
Water sold (millions of gallons)	**6,486**	6,370
Wastewater treated (millions of gallons)	**1,636**	1,592
Total Gallons Provided	**8,122**	7,962

During the nine months ended September 30, 2015, the water and wastewater distribution systems provided approximately 6,486 million gallons of water to its customers and treated approximately 1,636 million gallons of wastewater, as compared to 6,370 million gallons of water and 1,592 million gallons of wastewater during the same period in 2014. The increase can be primarily attributed to the acquisition of the White Hall Water and Sewer System on May 30, 2014, and increased demand at the Pine Bluff Water System and certain Arizona service territories.

For the nine months ended September 30, 2015, revenue from water and wastewater treatment distribution systems totalled U.S. $25.9 million and U.S. $20.1 million, respectively, as compared to U.S. $24.9 million and U.S. $19.2 million, respectively, during the same period in 2014. The increase in total water wastewater treatment distribution system revenue was primarily due to an increase in rates at the LPSCo Water and Sewer System, effective May 1, 2014, the acquisition of the White Hall Water and Sewer System on May 30, 2014, an increase in volumes and rates at the Pine Bluff Water System, and an increase in demand in certain Arizona service territories.

Other Revenue

For the nine months ended September 30, 2015, other revenue totalled U.S. $12.0 million, as compared to U.S. $2.0 million during the same period in 2014. The other revenue primarily consists of revenue earned from contracted services.

Operating Expenses

For the nine months ended September 30, 2015, operating expenses, excluding commodity purchases, totalled U.S. $128.9 million, as compared to U.S. $121.1 million during the same period in 2014, an increase of U.S. $7.8 million. The major factors resulting in the year over year increase in the group's operating expenses are set out as follows:

(all dollar amounts in U.S. $ millions)	**Nine months ended September 30, 2015**	
Comparative Prior Period Operating Expenses	$	121.1
Significant Changes:		
Increase in costs for contracted services		2.5
Increase in utility operating expenses		3.2
Increase in operating costs due to acquisition of utilities		1.8
Other		0.3
Current Period Operating Expenses	$	128.9

The increase in operating expenses can be primarily attributed to an increase in labour and contracted services, increased local administrative costs, and fewer capital-related work projects completed due to extreme winter weather conditions, which resulted in a decreased capitalization rate as compared to the same period in 2014, partially offset by lower bad debt expenses.

Recently completed acquisitions of New Hampshire Gas on January 2, 2015 and White Hall Water System on May 30, 2014 resulted in increased operating expense of U.S $1.8 million, as compared to the similar period in 2014.

Regulatory Proceedings

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

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Pending Rate Cases				
CalPeco Electric System	California	General Rate Case	$13.6	Application filed in May 2015 seeking a U.S. $13.6 million revenue increase effective January 2016. A final permanent rate decision is expected in Q2 2016.
Black Mountain Sewer System	Arizona	General Rate Case	$0.4	Application filed in June 2015 seeking a U.S. $0.4 million revenue increase. A final permanent rate decision is expected in Q3 2016.
New England Gas System	Massachusetts	General Rate Case	$11.8	Application filed in July 2015 seeking a U.S. $11.8 million revenue increase. A final permanent rate decision is expected in Q2 2016.
Peach State Gas System	Georgia	GRAM	$3.4	Application filed on October 2015 seeking a U.S. $3.4 million revenue increase. A final order is expected in Q4 2015, with new rates effective February 2016.
Rio Rico Water/Sewer System	Arizona	General Rate Case	$0.9	Application filed in October 2015 seeking a U.S. $0.9 million revenue increase. A final permanent rate decision is expected in Q4 2016.
Bella Vista Water System	Arizona	General Rate Case	$1.6	Application filed in October 2015 seeking a U.S. $1.6 million revenue increase. A final permanent rate decision is expected in Q4 2016.

Pending Rate Cases and Other Applications of Note

On May 1, 2015, the CalPeco Electric System filed an application with the California Public Utilities Commission ("CPUC") seeking an increase in revenue of U.S. $13.6 million, or 17.3%, based on a test year ending December 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The increase reflects a requested return on equity of 10.5% and a debt/equity structure of 45%/55%. The previous test year ended December 31, 2011. New permanent rates are proposed to be effective in the first quarter of 2016.

On June 22, 2015, the Black Mountain Wastewater System filed a rate case and financing application. The application seeks an increase in revenue requirement of U.S. $0.4 million, or 18.75%, based on a test year ending December 31, 2014. This rate case is primarily designed to resolve issues related to rate design and closure of the treatment plant. No amounts have been removed from rate base in this application. The increase reflects a requested return on equity of 1.8% and a debt/equity structure of 30%/70%. A final decision and implementation of new rates is expected for the third quarter of 2016.

On July 16, 2015, the New England Gas System filed an application with the Massachusetts Department of Public Utilities seeking an increase in revenue of U.S. $11.8 million, or 14.6%, based on a test year ending December 31, 2014, adjusted for known and measurable changes. This application represents the first rate case under the Distribution Group's ownership and the first since 2009. The New England Gas System requests the increase in its general rates for increasing capital costs associated with maintaining the infrastructure and increases in operating and maintenance expenses. The increase reflects a requested return on equity of 10.4% and a debt/equity structure of 45%/55%. A decision on this application is expected in the second quarter of 2016.

On October 1, 2015, the Peach State Gas System filed an application for an increase in revenue of U.S. $3.4 million in its annual "GRAM filing with the Georgia Public Service Commission. New rates to be effective February 1, 2016, for the period February 1, 2016, through January 31, 2017, will reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 2015 (historic test year), with adjustments for the 12 months ending September 2016 (forward looking test year). Commission approval is anticipated in the fourth quarter of 2015.

On October 28, 2015, the Rio Rico Water and Wastewater System filed a rate case and financing application. The application seeks a combined increase in revenue requirement of U.S. $0.9 million, based on a test year ending December 31, 2014, a combined rate base of U.S. $14.2 million, 10.8% ROE, and 70% equity, for an overall rate of return of 8.6%. The proposed revenue increases are U.S. $0.7 million, or 22.6%, for the water division and U.S. $0.2 million, or 15.3%, for the wastewater division. This rate case is primarily needed to recover increased operating costs and capital improvements. It also includes approval for the fair value Arizona rate evaluation model (“FARE”), a purchased power adjuster mechanism (“PPAM”) and a property tax adjuster mechanism (“PTAM”). The FARE allows for a periodic update of all components in the revenue requirement (subject to an earnings band). A final decision and implementation of new rates is expected for the fourth quarter of 2016. Its previous rate case was based on a test year ending February 2012.

On October 28, 2015, the Bella Vista Water System filed a rate case and financing application. The application seeks an increase in revenue requirement of U.S. $1.6 million, or 33.6%, based on a test year ending December 31, 2014, a rate base of U.S. $13.2 million, 11.6% ROE, and 70% equity, for an overall rate of return of 9.16%. This rate case is primarily needed to recover increased operating costs and capital improvements. It also includes approval for the FARE, a purchased power adjuster mechanism (“PPAM”) and a property tax adjuster mechanism (“PTAM”). A final decision and implementation of new rates is expected for the fourth quarter of 2016. Its previous rate case was based on a test year ending March 2009.

Other Applications of Note

On June 30, 2015, the Missouri Natural Gas System filed an application with the Missouri Public Service Commission seeking to change the infrastructure system replacement surcharge ("ISRS") to seek recovery for incremental rate base of U.S. $3.2 million and an annual revenue requirement of U.S. $0.4 million. A decision was issued in September 2015 approving a U.S. $0.3 million revenue requirement increase with an effective date of October 1, 2015.

In April 2014, the CalPeco Electric System filed an application with the California Public Utilities ("CPUC") seeking to recover U.S. $2.1 million recorded within its Vegetation Management Memorandum Account ("VMMA") during the period May 2012 through December 2012. A proposed decision was issued in September 2015 supporting 100% recover of the VMMA costs. This was followed by an Order from the CPUC on October 22, 2015 supporting the cost recovery.

Related to the above CalPeco Electric System rate application are two additional applications in California. The first is an Application filed with the CPUC on April 17, 2015 for the issuance of a Certificate of Public Convenience and Necessity (“CPCN”) to acquire, own and operate a solar power generation station with a total generation capacity of up to 60MW (the “Solar Project”). The application requested authorization for rate recovery of the costs that the CalPeco Electric System will incur to acquire, own, and operate the Solar Project. The second is an Application filed on April 24, 2015 with the CPUC requested authority to enter into a new multi-year Services Agreement with NV Energy commencing January 2016 and authority to recover the costs it will incur under the 2016 NV Energy Services Agreement as energy purchase costs. This new PPA is required as an existing PPA with NV Energy expires at the end of 2015. The Distribution Group believes these two applications allow the CalPeco Electric System to continue procurement of its energy supply in a cost-effective manner for its customers and allow the utility to meet its Renewables Portfolio Standard requirements. A settlement in the Solar Application was achieved and subsequently filed with the CPUC in August 2015. An Order is expected in fourth quarter of 2015. Discovery is ongoing in the PPA docket, and Q4 approval is anticipated.

The EnergyNorth Natural Gas System in New Hampshire recently filed three applications with the New Hampshire Public Utilities Commission to obtain the franchise rights to provide gas to new territories. One was filed in July 2015 seeking approval to obtain the franchise rights to the Town of Hanover and City of Lebanon. This docket is expected to conclude in the first quarter of 2016. A second was filed in August 2015 seeking the franchise rights to the towns of Pelham and Windham. This docket is expected to conclude in the fourth quarter of 2015. A third application was filed in October 2015 to serve the towns of Jaffrey, Rindge, Swanzey, and Winchester. This docket is expected to conclude in the second quarter of 2016.

Acquisition Approval Applications

On September 19, 2014, the Distribution Group announced the entering into an agreement to acquire the regulated water distribution utility, Park Water Company (“Park Water System”). Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. The three utilities collectively serve approximately 74,000 customer connections and have more than 1,000 miles of distribution mains.

The acquisition requires the approval of both the CPUC and the Montana Public Service Commission ("MPSC"). An approval application was filed on November 24, 2014, with the CPUC seeking approval for Liberty Utilities Co. to effectively acquire the two water utilities located in California owned by the Park Water Company: the Park Central Basin Water and Apple Valley Ranchos Water Systems. A Joint Settlement Agreement was executed with the Office of the Ratepayer Advocate and a Joint Motion to Approve Settlement was filed on May 29, 2015. The Settlement Agreement is currently before the Administrative Law Judge and a decision is expected in the fourth quarter of 2015. An approval application was also filed on December 15, 2014, with the MPSC seeking approval for Liberty Utilities Co. to acquire Mountain Water Company. Discovery is ongoing.

TRANSMISSION BUSINESS GROUP

In 2014 APUC formed its Transmission Group and announced an agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan, Inc. ("Northeast Expansion LLC") to undertake the development, construction and ownership of a natural gas transmission pipeline to be located between Wright, NY and Dracut, MA (the “Project”). The Transmission Group will initially subscribe for a 2.5% interest in Northeast Expansion LLC. APUC also has an opportunity to increase its participation up to 10%.

The Transmission Group expects to invest approximately $5.0 million (U.S. $3.8 million) for the natural gas pipeline transmission project in the current year. The cost of the project are being classified as a long term investment on the unaudited interim consolidated balance sheet (see note 6).

The Project is in the early phases of permitting and development. On July 24, 2015, the second draft of the Environmental Review was filed with FERC. This Environmental Review provides an update to FERC on environmental considerations related to the proposed route. A formal FERC certificate application containing a full environmental review will be filed on November 20, 2015. Construction is expected to begin in January 2017 and commercial operations by November 1, 2018.

On July 16, 2015, Kinder Morgan announced that it is proceeding with the Northeast Energy Direct Project at an estimated capital cost of U.S. $3.3 billion subject to receiving all applicable permits. In late September 2015, the Project (through its Developer - Tennessee Gas Pipeline) announced an Open Season designed to attract additional power generation loads in the Northeast. This is in concert with several states, which include New Hampshire, Massachusetts and Connecticut moving forward with regulatory initiatives to support the pass through of power generators long term pipeline capacity costs to support further infrastructure development. To date, both the New Hampshire and Massachusetts regulatory commissions have approved the gas distribution utility’s contractual commitments to the Project.

APUC: Corporate and Other Expenses

	Three months ended September 30,		Nine months ended September 30,	
(all dollar amounts in $ millions)	**2015**	**2014**	**2015**	**2014**
Corporate and other expenses:				
Administrative expenses	**$ 8.5**	$ 8.2	**$ 27.5**	$ 24.2
(Gain)/Loss on foreign exchange	**(1.6)**	(0.5)	**(2.9)**	(1.4)
Interest expense	**15.4**	15.9	**48.6**	48.3
Interest, dividend and other Income[1]	**(0.9)**	(0.7)	**(1.9)**	(2.7)
Write down of long lived assets	**1.5**	7.2	**1.8**	7.8
Acquisition-related costs	**0.6**	0.4	**1.4**	0.9
(Gain)/Loss on derivative financial instruments	**0.2**	(1.6)	**(2.2)**	(0.7)
Income tax expense	**3.1**	(4.5)	**32.0**	13.1

1 Excludes income directly pertaining to the Generation and Distribution Groups (disclosed in the relevant sections).

2015 Third Quarter Corporate and Other Expenses

During the three months ended September 30, 2015, administrative expenses totalled $8.5 million, as compared to $8.2 million in the same period in 2014. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the company's growth.

For the three months ended September 30, 2015, interest expense totalled $15.4 million, as compared to $15.9 million in the same period in 2014. The decrease primarily relates to a write-off of premium related to the retirement of the LPSCO debt subsequent to the quarter.

For the three months ended September 30, 2015, interest, dividend and other income totalled $0.9 million, as compared to $0.7 million in the same period in 2014, an increase of $0.2 million.

For the three months ended September 30, 2015, acquisition-related costs totalled $0.6 million as compared to $0.4 million in the same period in 2014. Acquisition-related costs will vary from period to period depending on the level of activity and complexity associated with various acquisitions.

An income tax expense of $3.1 million was recorded in the three months ended September 30, 2015, as compared to an income tax recovery of $4.5 million during the same period in 2014. The increase in income tax expense for the three months ended September 30, 2015, is primarily due to increased earnings from operations, and a stronger U.S. dollar.

2015 Nine Month Corporate and Other Expenses

During the nine months ended September 30, 2015, administrative expenses totalled $27.5 million, as compared to $24.2 million in the same period in 2014. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the company's growth.

For the nine months ended September 30, 2015, interest expense totalled $48.6 million, as compared to $48.3 million in the same period in 2014.

For the nine months ended September 30, 2015, interest, dividend and other income totalled $1.9 million, as compared to $2.7 million in the same period in 2014, a decrease of $0.8 million due to no dividends received from the Cochrane investment in 2015.

For the nine months ended September 30, 2015, acquisition-related costs totalled $1.4 million as compared to $0.9 million in the same period in 2014. Acquisition-related costs will vary from period to period depending on the level of activity and complexity associated with various acquisitions.

An income tax expense of $32.0 million was recorded in the nine months ended September 30, 2015, as compared to an income tax expense of $13.1 million during the same period in 2014. The increase in income tax expense for the nine months ended September 30, 2015, is primarily due to increased earnings from operations, increased deferred taxes on HLBV income, a stronger U.S. dollar, a one-time non-cash charge of $2.7 million to deferred income taxes as a result of an agreement reached with the CRA related to the Unit Exchange Transaction (see Operational Risk Management - Tax Risk and Uncertainty), and other items permanently non-deductible for tax purposes.

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 statement 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)	**2015**	**2014**	**2015**	**2014**
Net earnings/(loss) attributable to Shareholders	**$ 16.5**	$ (6.3)	**$ 79.5**	$ 44.1
Add (deduct):				
Net earnings attributable to the non-controlling interest, exclusive of HLBV	**0.2**	0.3	**1.3**	4.5
Loss from discontinued operations	**0.2**	0.2	**1.0**	0.6
Income tax expense/(recovery)	**3.1**	(4.5)	**32.0**	13.1
Interest expense	**15.4**	15.9	**48.6**	48.3
Other gains	**(0.6)**	—	**(3.0)**	—
Non-cash write downs	**1.5**	7.2	**1.8**	7.8
Acquisition costs	**0.6**	0.4	**1.4**	0.9
(Gain) / Loss on derivative financial instruments	**0.2**	(1.6)	**(2.2)**	(0.7)
Realized gain / (loss) on energy derivative contracts	**—**	(0.2)	**0.6**	3.8
(Gain) / Loss on foreign exchange	**(1.6)**	(0.5)	**(2.9)**	(1.4)
Depreciation and amortization	**34.7**	30.5	**107.9**	85.1
Adjusted EBITDA	**$ 70.2**	$ 41.4	**$ 266.0**	$ 206.1

HLBV represents the value of net tax attributes earned by the Generation Group in the period from electricity generated by certain of its U.S. wind and solar powered generation facilities. The value of net tax attributes earned in the three and nine months ended September 30, 2015, amounted to approximately $4.5 million and $21.4 million, respectively.

For the three months ended September 30, 2015, Adjusted EBITDA totalled $70.2 million as compared to $41.4 million, an increase of $28.8 million. For the nine months ended September 30, 2015, Adjusted EBITDA totalled $266.0 million, as compared to $206.1 million during the same period in 2014, an increase of $59.9 million.

The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

(all dollar amounts in $ millions)	Three months ended September 30	Nine months ended September 30
Comparative Prior Period Adjusted EBITDA	$ 41.4	$ 206.1
Significant Changes:		
Decrease in hydrology resources in the Western and Maritime regions, coupled with decreased customer load and retail pricing in the Maritime region.	(1.3)	(3.6)
Decrease in wind resource (but increase in 3rd quarter) partially offset by unfavorable settlements in the prior year on periodic production shortfalls under power hedges and higher pricing realized on sales of the unhedged portion of energy produced.	5.4	2.3
Start of commercial operations of the St. Damase (Q4'14) and Morse (Q2'15) Wind Facilities.	3.0	7.9
Start of commercial operations at the Cornwall (Q1'14) and Bakersfield I (Q2'15) Solar Facilities.	0.9	2.7
Higher realized prices on sale of Renewable Energy Credits offset by decreased production.	0.4	1.6
Lower realized prices at the Sanger and Windsor Locks Thermal Facilities combined with lower production.	—	(1.5)
Increase due to implementation of general rate increases at the EnergyNorth Gas System, the Missouri Gas System, the Illinois Gas system, Peach State Gas System, and the LPSCO Water system.	4.0	17.7
Decrease at the Granite State Electric System due to $1.6 million of additional revenue recognized in the first quarter of 2014 pertaining to the difference in the interim rates and final rates recognized as part of the last rate case.	—	(1.6)
Increased in contracted services.	6.3	7.8
Increase in administrative expense.	(0.9)	(3.9)
Increased results from the stronger U.S. dollar	11.0	31.7
Other	—	(1.2)
Current Period Adjusted EBITDA	$ 70.2	$ 266.0

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 statement 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)	**2015**	**2014**	**2015**	**2014**
Net earnings / loss attributable to Shareholders	**$ 16.5**	$ (6.3)	**$ 79.5**	$ 44.1
Add (deduct):				
(Gain) / Loss from discontinued operations, net of tax	**0.2**	0.2	**1.0**	0.6
(Gain) / Loss on derivative financial instruments, net of tax	**0.1**	(1.0)	**(1.3)**	(0.4)
Realized gain / (loss) on derivative financial instruments, net of tax	**(0.4)**	(0.5)	**(0.7)**	1.2
Write-down on long lived assets	**1.5**	7.2	**1.8**	7.8
(Gain) / Loss on foreign exchange, net of tax	**(1.0)**	(0.3)	**(1.8)**	(0.9)
Deferred tax expense due to CRA agreement related to the Unit Exchange Transaction	**—**	—	**2.7**	—
Acquisition costs, net of tax	**0.4**	0.3	**0.8**	0.6
Adjusted net earnings / (loss)	**$ 17.3**	$ (0.4)	**$ 82.0**	$ 53.0
Adjusted net earnings / (loss) per share	**$ 0.06**	$ (0.01)	**$ 0.31**	$ 0.22

For the three months ended September 30, 2015, adjusted net earnings totalled $17.3 million, as compared to adjusted net loss of $0.4 million, an increase of $17.7 million as compared to the same period in 2014. The increase in adjusted net earnings for the three months ended September 30, 2015, is primarily due to higher income from operations partially offset by higher operating expense, as well as depreciation and amortization expense as compared to the same period in 2014.

For the nine months ended September 30, 2015, adjusted net earnings totalled $82.0 million, as compared to adjusted net earnings of $53.0 million, an increase of $29.0 million as compared to the same period in 2014. The increase in adjusted net earnings for the nine months ended September 30, 2015, is primarily due to higher income from operations partially offset by higher operating expense, as well as depreciation and amortization expense as compared to the same period in 2014.

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 statement of operations and 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:

	Three months ended September 30,		Nine months ended September 30,	
(all dollar amounts in $ millions)	**2015**	**2014**	**2015**	**2014**
Cash flows from operating activities	**$ 76.2**	(3.1)	**$ 167.5**	$ 96.3
Add (deduct):				
Changes in non-cash operating items	**(22.9)**	21.1	**28.9**	33.6
Cash used in discontinued operations	**0.4**	0.3	**1.7**	0.8
Production based cash contributions from non-controlling interests	**—**	—	**10.8**	9.0
Acquisition costs	**0.6**	0.4	**1.4**	0.9
Adjusted funds from operations	**$ 54.3**	$ 18.7	**$ 210.3**	$ 140.6
Adjusted funds from operations per share	**$ 0.22**	$ 0.08	**$ 0.85**	$ 0.65

For the three months ended September 30, 2015, adjusted funds from operations totalled $54.3 million, as compared to adjusted funds from operations of $18.7 million, an increase of $35.6 million as compared to the same period in 2014.

For the nine months ended September 30, 2015, adjusted funds from operations totalled $210.3 million, as compared to adjusted funds from operations of $140.6 million, an increase of $69.7 million as compared to the same period in 2014.

Summary of Property, Plant, and Equipment

	Three months ended September 30,		Nine months ended September 30,	
(all dollar amounts in $ millions)	**2015**	**2014**	**2015**	2014
GENERATION GROUP				
Renewable	**$ 21.5**	61.5	**$ 49.7**	$ 137.4
Thermal	**0.8**	0.5	**1.4**	3.5
Total Generation Business Group	**$ 22.3**	$ 62.0	**$ 51.1**	$ 140.9
DISTRIBUTION GROUP	**57.4**	45.0	**$ 107.7**	$ 99.5
Corporate	**0.4**	4.3	**3.0**	50.2
Total	**$ 80.1**	$ 111.3	**$ 161.8**	$ 290.6

The company's updated consolidated capital expenditure plan for 2015 is approximately $233.0 million, which is down by approximately $40.0 million from the figure previously reported, due to certain cash expenditures now expected to take place in the first quarter of 2016. The Generation Group expects to invest approximately $68.0 million primarily in connection with its development portfolio. The Distribution Group expects to invest approximately $165.0 million (U.S. $123.9 million) primarily to improve the reliability and efficiency of its gas and electric utility distribution systems.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, revolving credit facilities, as well as the debt and equity capital markets to finance its property, plant and equipment expenditures and other commitments.

2015 Third Quarter Property Plant and Equipment Expenditures

During the three months ended September 30, 2015, the Generation Group incurred capital expenditures of $22.3 million, as compared to $62.0 million during the comparable period in 2014.

During the three months ended September 30, 2015, the Generation Group's Renewable Energy Division spent $21.5 million in capital expenditures, as compared to $61.5 million in the comparable period in 2014. The capital expenditures primarily relate to the construction of the Bakersfield II Solar and the Chaplin, Amherst, and ValEo Wind Projects. The Generation Group's Thermal Energy Division net capital expenditures were $0.8 million, as compared to $0.5 million in the comparable period in 2014.

During the three months ended September 30, 2015, the Distribution Group invested $57.4 million (U.S. $43.8 million) in capital expenditures, as compared to $45.0 million (U.S. $41.3 million) during the comparable period in 2014. The Distribution Group's capital expenditures primarily related to reliability enhancements, improvement and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection systems relating to safety and reliability at the gas systems.

2015 Nine Month Property Plant and Equipment Expenditures

During the nine months ended September 30, 2015, the Generation Group incurred capital expenditures of $51.1 million, as compared to $140.9 million during the comparable period in 2014.

During the nine months ended September 30, 2015, the Generation Group's Renewable Energy Division spent $49.7 million in capital expenditures, as compared to $137.4 million in the comparable period in 2014. The capital expenditures primarily relate to the completion of the Bakersfield I Solar and Morse Wind Projects, and the construction of the Bakersfield II Solar and the Chaplin, Amherst and ValEo Wind Projects. The Generation Group's Thermal Energy Division net capital expenditures were $1.4 million, as compared to $3.5 million in the comparable period in 2014.

During the nine months ended September 30, 2015, the Distribution Group invested $107.7 million (U.S. $82.3 million) in capital expenditures, as compared to $99.5 million (U.S. $90.9 million) during the comparable period in 2014. The Distribution Group's capital expenditures primarily related to reliability enhancements, improvement and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection systems relating to safety and reliability at the gas systems.

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C-93), the Generation Group has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. Out of these, nine assessments have been submitted to and accepted by the Quebec government. The assessments have identified possible remedial work at seven facilities. Of these seven, remediation work has now been completed at three facilities, monitoring activities and options analysis are being performed for two facilities, and remedial work is being planned at two facilities.

The Generation Group currently estimates further capital expenditures of approximately $8.0 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

(all dollar amounts in $ millions)	Total	2015	2016	2017	2018
Future Estimated Bill C-93 Capital Expenditures	$ 8.0	0.6	3.6	3.5	0.3

The majority of these capital costs are associated with the Belleterre, Rivière-du-Loup, and St. Alban Hydro Facilities.

The Generation Group has been working with the provincial authorities to reclassify, decommission or remove several small dams upstream of the Belleterre Hydro Facility that are not required for power generation. During the first quarter of 2015, four dams were declassified and removed from the CEHQ's registry, while three others were reclassified to Class E (Very Low Consequence) dams, from higher classes. Upon the recommendation of third party engineers, the Generation Group is in discussion with the relevant government ministries to postpone the decommissioning work on these dams for five years to allow sufficient time to determine the new decommissioning requirements and develop new project plans.

Liquidity and Capital Reserves

APUC has revolving operating facilities available for APUC, the Generation Group and the Distribution Group to manage the liquidity and working capital requirements of each division (collectively the "Facilities").

Bank Credit Facilities

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its operating groups as at September 30, 2015, under the Facilities:

	As at September 30, 2015				As at Dec 31 2014
(all dollar amounts in $ millions)	Corporate	Generation Group	Distribution Group	Total	Total
Committed Facilities	$ 65.0	$ 350.0	$ 266.9	$ 681.9	$ 647.0
Funds drawn on Facilities	(18.7)	(155.3)	—	(174.0)	(47.3)
Letters of Credit issued	(12.5)	(100.2)	(10.7)	(123.4)	(113.8)
Funds available for draws on the Facilities	**$ 33.8**	**$ 94.5**	**$ 256.2**	**$ 384.5**	$ 485.9
Cash on Hand				52.1	9.3
Total liquidity and capital reserves	**$ 33.8**	**$ 94.5**	**$ 256.2**	**$ 436.6**	$ 495.2

As at September 30, 2015, the Company's $65.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility"), was drawn $18.7 million and had $12.5 million of outstanding letters of credit. The facility matures on November 19, 2016, and is subject to customary covenants.

As at September 30, 2015, the Generation Group's $350.0 million Credit Facility ("Generation Credit Facility") had drawn $155.3 million and had $100.2 million in outstanding letters of credit. During the second quarter the Generation Group extended the maturity date of the Generation Credit Facility by one year to July 31, 2019.

As at September 30, 2015, the Distribution Group's $266.9 million (U.S. $200.0 million) senior unsecured revolving credit facility (the "Distribution Credit Facility") was undrawn and had $10.7 million (U.S. $8.0 million) of outstanding letters of credit. The facility matures on September 30, 2018, and is subject to customary covenants.

On October 30, 2015, the Generation Group entered into a new extendible one year Generation LC Facility. The new facility expands the group's available liquidity by providing for issuances of letters of credit up to a maximum of $50 million Canadian, and $30 million U.S. dollars. Upon closing, certain letters of credit issued under the existing Generation Credit Facility were transferred to the new facility.

Long Term Debt

On April 30, 2015, the Distribution Group entered into a Note Purchase Agreement for the issuance of U.S. $160.0 million of senior unsecured 30 year notes bearing a coupon of 4.13% via a private placement in the U.S. The proceeds of the financing will be used to partially finance the acquisition of the Park Water System and for general corporate purposes. The note was issued in two tranches: U.S. $90 million was issued immediately on closing and U.S. $70 million was issued on July 15, 2015. The notes have been assigned a rating of BBB High by DBRS. The financing is the fourth series of notes issued pursuant to the company's master indenture.

Subsequent to the quarter on October 1, 2015 the Distribution Group repaid the U.S. $9.8 million outstanding under the LPSCo Water System IDA bonds.

As at September 30, 2015, the weighted average tenor of APUC's total long term debt is approximately 9.9 years with an average interest rate of 4.77%.

Contractual Obligations

Information concerning contractual obligations as of September 30, 2015, 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
Long-term debt obligations	**1,622.8**	21.7	238.5	216.6	1,146.0
Advances in aid of construction	**89.2**	1.3			87.9
Interest on long-term debt obligations	**684.9**	78.2	148.1	120.0	338.6
Purchase obligations	**158.3**	158.3			
Environmental obligation	**73.1**	9.7	36.1	3.3	24.0
Derivative financial instruments:					
Cross currency swap	**84.5**	3.9	7.3	6.1	67.2
Interest rate forward	**9.4**	—	—	9.4	—
Energy derivative contracts	**2.9**	2.7	0.2		
Capital projects	**12.7**	5.2	7.5	—	—
Long Term Service agreements	**688.8**	35.8	70.1	69.5	513.4
Purchased power	**449.2**	95.3	114.7	130.3	108.9
Gas delivery, service and supply agreements	**301.1**	62.1	81.6	67.5	89.9
Operating leases	**130.5**	6.3	10.1	9.3	104.8
Other Obligations	**51.1**	12.6	1.0	—	37.5
Total obligations	**4,358.5**	**493.1**	**715.2**	**632.0**	**2,518.2**

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at September 30, 2015, APUC had 240,486,844 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.

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, 2015, 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 shares of APUC. As at September 30, 2015, 69,407,804 common shares representing approximately 28.7% of total shares outstanding had been registered with the Reinvestment Plan. During the quarter ended September 30, 2015, 907,017 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on October 15, 2015, an additional 997,532 common shares were issued under the Reinvestment Plan.

Emera shareholdings and subscription receipts

As at November 5, 2015, in total, Emera owns 50,126,766 APUC common shares representing approximately 20.8% of the total outstanding common shares of the Company, and 12,024,753 subscription receipts.

Share Based Compensation Plans

For the three and nine months ended September 30, 2015, APUC recorded $1.6 million and $3.7 million (2014 - $1.1 million and $2.1 million) 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 at September 30, 2015, total unrecognized compensation costs related to non-vested options and share unit awards were $4.1 million and $2.5 million respectively, and are expected to be recognized over a period of 1.9 years and 1.8 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.

As at September 30, 2015, a total of 7,164,652 options had been granted and outstanding under the plan.

Performance Share Units

APUC issues performance share units ("PSUs") to certain members of management other than senior executives as part of APUC's long-term incentive program. The PSUs provide for settlement in cash or common shares at the election of APUC. As the Company expects to settle the PSU's in common shares, the PSUs are accounted for as equity awards.

As at September 30, 2015, a total of 573,879 PSU's had been granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. The DSUs provide for settlement in cash or common shares at the election of APUC. As APUC does not expect to settle the DSU's in cash, these DSUs are accounted for as equity awards.

As at September 30, 2015, a total of 144,118 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 common shares.

As at September 30, 2015, a total of 321,723 shares had been issued under the ESPP.

Related Party Transactions

A member of the Board of Directors of APUC is an executive at Emera. For the three and nine months ended September 30, 2015, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), and Bangor Hydro ("BH") subsidiaries of Emera, amounting to U.S. $1.7 million and U.S. $5.3 million, respectively (2014 - U.S. $2.0 million and U.S. $8.2 million). For the three and nine months ended September 30, 2015, Liberty Utilities purchased natural gas amounting to U.S. $Nil and U.S. $1.3 million, respectively (2014 - U.S. $0.1 million and U.S. $4.9 million) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process the results of which were approved by the regulator in the relevant jurisdiction.

There were no amounts outstanding related to these transactions at the end of the periods.

As at September 30, 2015, $nil (December 31, 2014 - $0.05 million) was due from Algonquin Power Systems Ltd., a corporation partially owned by Ian Robertson and Chris Jarratt (collectively "Senior Executives").

Chartered Aircraft

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into a block time agreement to charter aircraft in which Senior Executives have a partial ownership. The Company terminated the agreement effective June 28, 2015 and paid a usage shortfall fee of $13. During the three and nine months ended September 30, 2015, APUC reimbursed direct costs in connection with the use of the aircraft prior to termination of the block time agreement of $0.2 million and $0.6 million (2014 - $0.1 million and $0.4 million).

Office Facilities

Until the fourth quarter of 2014 APUC had leased its head office facilities from an entity partially owned by Senior Executives. During the fourth quarter of 2014, APUC terminated the related party lease and moved all head office employees into new premises owned by the Company. Base lease costs for the three and nine months ended September 30, 2015 were $nil (2014 - $0.09 million and $0.3 million).

Other

A spouse of one of the Senior Executives was employed to provide market research services to certain subsidiaries of the Company. During the three and nine months ended September 30, 2015 APUC paid $Nil and $0.02 million (2014 - $0.07 million and $0.1 million) in relation to these services. The spouse is no longer employed by the Company.

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction is expected to be settled by the end of 2015 or in early 2016.

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. APUC's ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. Reference should be made to APUC's most recent annual MD&A and its most recent AIF.

Treasury Risk Management

Market Price Risk

The Distribution Business Group is not exposed to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

The Generation Group has certain market price risk exposures and takes steps to mitigate those risks.

On May 15, 2012, the Generation Group entered into a financial hedge, which expires December 31, 2016, with respect to its Dickson Dam Hydro Facility located in the Western region. The financial hedge is structured to hedge 75% of the facility's expected production volume against exposure to the Alberta Power Pool's current spot market rates. The annual unhedged production based on long term projected averages is approximately 16,000 MW-hrs annually. Therefore, each $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of $0.2 million on an annualized basis.

The July 1, 2012, acquisition of 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 annually. Therefore, each U.S. $10 per MW-hr change in the market prices would result in a change in revenue of about U.S. $0.4 million for the year.

The December 10, 2012 acquisition of 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 annually. Therefore, each U.S. $10 per MW-hr change in the market prices would result in a change in revenue of about U.S. $1.9 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 annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of about U.S. $1.9 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 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 Generation 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.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on January 1, 2013, 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 about U.S. $0.5 million for the year.

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 Credit Facility is subject to a variable interest rate. The APUC Facility had $18.7 million outstanding as at September 30, 2015. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Generation Credit Facility had $155.3 million outstanding as at September 30, 2015. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.6 million annually.
- The Distribution Credit Facility had no amounts outstanding as at September 30, 2015. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.

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. The interest rate swap, although not designated as a hedge, serves to partially offset interest rate movements against the variable pay portion of the Company's debt.

To mitigate refinancing risk, from time to time APUC may seek to fix interest rates on expected future financings. The Generation Group has entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded into Other Comprehensive Income.

Liquidity Risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due.

Both the Generation Group and the Distribution Group have established financing platforms to access new liquidity from the capital markets as requirements arise. APUC continually monitors the maturity profile of its debt and adjusts accordingly to ensure sufficient liquidity exists to meet liabilities when due.

As at September 30, 2015, APUC and its subsidiaries had a combined $384.5 million of committed and available revolving credit facilities remaining and $52.1 million of cash resulting in $436.6 million of total liquidity and capital reserves.

APUC currently pays a dividend of U.S. $0.3850 per common share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements, and to fund working capital that, in its judgment, ensures APUC's long-term success.

The current and long term portion of debt totals approximately $1,613.3 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facilities and project debt with borrowings having less favorable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted.

The cash flow generated from several of APUC's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regard to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and APUC losing its investment in such operating facility. APUC actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

Operational Risk Management

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. The following are material updates to the annual MD&A for the year ended December 31, 2014.

Trafalgar Proceedings

Trafalgar commenced an action in 1999 in U.S. District Court against various Algonquin entities in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to the Algonquin entities and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the “Trafalgar Hydro Facilities”). Over the past 16 years there have been various legal proceedings and appeals in connection with this matter. Currently both the Algonquin entities and Trafalgar have certain motions before the Bankruptcy Court seeking determinations on a number of matters. Those motions are under consideration by the Bankruptcy Court.

The Bankruptcy Court has approved the sale of all seven of the Trafalgar Hydro Facilities all of which have now been closed. It is anticipated that the parties will attempt to settle this long standing lawsuit through mediation.

Long Sault Global Adjustment Claim

In December 2012, N-R Power and Energy Corporation, Algonquin Power (Long Sault) Partnership, and N-R Power Partnership (“Long Sault”) commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC’s interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global adjustment (“GA”) as a price escalator. On March 12, 2015, the Ontario Superior Court of Justice ruled that the methodology that the OEFC used from January 1, 2011, onward to calculate payments under Long Sault's PPA, and those of other producers, did not comply with the terms of those PPAs. The decision further requires the OEFC to revert to its pre-2011 methodology for calculating payments and to pay producers the difference between the payments calculated by the OEFC since 2011 and the amount of the payments they would have received using the pre-2011 methodology, plus interest and costs. On April 10, 2015, the OEFC appealed to the Court of Appeal to set aside the Divisional Court’s judgment of March 12, 2015. The Court of Appeal hearing has been scheduled for December 14 and 15, 2015.

Tax Risk and Uncertainty

Earlier in the year APUC received correspondence from the CRA which outlined its intention to challenge the tax consequences of APUC's 2009 transaction whereby unit holders of Algonquin Power Income Fund exchanged their trust units on a one-for-one basis for common shares of APUC (the "Unit Exchange"). The CRA was seeking to apply the acquisition of control rules through application of the general anti-avoidance rule of the Income Tax Act (Canada), the effect of which would be to deny APUC the benefit of the tax attributes it assumed as part of the Unit Exchange Transaction.

On June 26, 2015, the Company entered into an agreement with the CRA resulting in a $16.0 million reduction in the APUC's deferred tax assets and a proportional reduction of $13.3 million in its deferred tax credits. Consequently, a $2.7 million net non-cash charge to deferred income tax expense was recorded in the Company's results for the second quarter of 2015

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the eight quarters ended September 30, 2015:

(all dollar amounts in $ millions except per share information)	4th Quarter 2014	1st Quarter 2015	2nd Quarter 2015	3rd Quarter 2015
Revenue	$ 259.3	$ 381.9	196.2	189.6
Adjusted EBITDA	84.3	114.5	81.1	70.2
Net earnings / (loss) attributable to shareholders from continuing operations	33.1	43.1	20.6	16.7
Net earnings / (loss) attributable to shareholders	31.6	43.1	19.9	16.5
Net earnings / (loss) per share from continuing operations	0.13	0.16	0.07	0.06
Net earnings / (loss) per share	0.13	0.16	0.07	0.05
Adjusted net earnings / (loss)	35.2	42.5	22.2	17.3
Adjusted net earnings / (loss) per share	0.14	0.17	0.08	0.06
Total Assets	4,105.1	4,531.4	4,396.5	4,759.0
Long term liabilities[1]	1,271.7	1,482.7	1,440.3	1,613.3
Dividend declared per common share	0.10	0.11	0.12	0.13
	4th Quarter 2013	**1st Quarter 2014**	**2nd Quarter 2014**	**3rd Quarter 2014**
Revenue	$ 205.3	$ 343.0	$ 188.6	151.6
Adjusted EBITDA	67.6	97.5	66.4	41.4
Net earnings / (loss) attributable to shareholders from continuing operations	19.8	35.6	15.3	(6.1)
Net earnings / (loss) attributable to shareholders	13.1	35.9	14.6	(6.3)
Net earnings / (loss) per share from continuing operations	0.09	0.16	0.06	(0.04)
Net earnings / (loss) per share	0.06	0.17	0.06	(0.04)
Adjusted net earnings	18.5	36.8	16.6	(0.4)
Adjusted net earnings per share	0.08	0.17	0.07	(0.01)
Total Assets	3,469.3	3,644.3	3,553.6	3,799.3
Long term liabilities[1]	1,248.3	1,400.9	1,381.0	1,404.3
Dividend declared per common share	0.09	0.09	0.09	0.10

[1] Long term debt includes current and long term portion of 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 $151.6 million and $381.9 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology 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 $43.1 million and a net loss of $6.3 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

Disclosure Controls

As of September 30, 2015, 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, 2015, 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 control 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.

For the nine months ended September 30, 2015, 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.

Critical Accounting Estimates and Policies

APUC prepared its unaudited interim 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 depreciable assets, 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.

Except for adopted accounting policies described below, the significant accounting policies and estimates applied to the unaudited interim consolidated financial statements of APUC for the nine months period ended September 30, 2015 are consistent with those disclosed in APUC's MD&A and Note 1 of its consolidated financial statements for the year ended December 31, 2014, available on SEDAR.

Effective January 1, 2015, the Company applied ASU 2015-03, Interest: Imputation of Interest (Subtopic 835-30) retrospectively to all prior periods presented in the financial statements. As a result, deferred financing costs that were previously presented as Other Assets on the consolidated balance sheets have been reclassified as a deduction from the carrying amount of the related long-term liabilities.

Individual components of a wind facility are recorded and depreciated separately in the books and records of the Company. Effective January 1, 2015, the Company changed the depreciation method from the straight-line method to the unit-of-production method for certain components of its wind generating facilities where the useful life of the component is directly related to the amount of production. The benefits of components that are subject to wear and tear from the power generation process are best reflected through the unit-of-production method. The Company generally uses wind studies prepared by third parties to estimate the total expected production of each component. This change in the depreciation method results from having better information on the consumption of the benefits of certain components that are directly related to production. The change is being recognized prospectively. The impact of the change on the operating results for the three and nine months period ended September 30, 2015, was a reduction of depreciation expense of $3.3 million and $4.3 million, respectively. The impact on basic and diluted net earnings per share for the three and nine months ended September 30, 2015 was an increase of $0.01 and $0.02, respectively. The change is not expected to materially affect net earnings or net earnings per share on an annual basis.

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	September 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 52,050	$ 9,273
Accounts receivable, net (note 4)	145,670	188,573
Natural gas in storage	27,834	31,550
Supplies and consumables inventory	15,280	11,825
Regulatory assets (note 5)	26,600	61,645
Prepaid expenses	14,695	10,431
Long-term investments (note 6)	35,095	2,966
Deferred income taxes (note 15)	23,324	7,210
Income taxes receivable (note 15)	509	568
Derivative instruments (note 20)	12,316	10,688
Other current assets	15,671	—
	369,044	334,729
Property, plant and equipment, net	3,718,075	3,278,422
Intangible assets, net	79,531	54,011
Goodwill	106,541	92,328
Regulatory assets (note 5)	207,682	187,860
Derivative instruments (note 20)	76,389	31,782
Long-term investments (note 6)	145,537	43,279
Deferred income taxes (note 15)	37,711	57,065
Other assets	18,485	25,605
	$ 4,758,995	$ 4,105,081

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	September 30, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 19,293	$ 68,540
Accrued liabilities	138,974	199,374
Dividends payable (note 12)	36,787	25,395
Regulatory liabilities (note 5)	35,084	20,590
Long-term liabilities (note 7)	21,719	9,130
Pension and other post-employment benefits (note 8)	383	333
Other long-term liabilities (note 9)	43,184	49,303
Derivative instruments (note 20)	6,606	5,183
Preferred shares, Series C	1,011	1,085
Income taxes liability (note 15)	4,583	3,633
Deferred income taxes (note 15)	371	3,702
	307,995	386,268
Long-term liabilities (note 7)	1,591,610	1,262,589
Regulatory liabilities (note 5)	115,855	101,166
Deferred income taxes (note 15)	201,237	130,758
Derivative instruments (note 20)	90,095	40,088
Pension and other post-employment benefits (note 8)	153,771	138,602
Other long-term liabilities (note 9)	185,465	179,468
Preferred shares, Series C	17,555	17,608
	2,355,588	1,870,279
Redeemable non-controlling interest (note 3(c))	10,934	12,146
Equity:		
Preferred shares	213,805	213,805
Common shares (note 10(a))	1,654,360	1,633,262
Subscription receipts	110,503	110,503
Additional paid-in capital	36,513	33,068
Deficit	(524,463)	(505,305)
Accumulated other comprehensive income (note 11)	238,148	34,213
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,728,866	1,519,546
Non-controlling interests	355,612	316,842
Total equity	2,084,478	1,836,388
Commitments and contingencies (note 18)		
Subsequent events (notes 6, 7 and 12)		
	$ 4,758,995	$ 4,105,081

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, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Revenue				
Regulated electricity distribution	$ 53,370	$ 48,606	$ 169,526	$ 150,318
Regulated gas distribution	49,304	42,244	349,528	321,370
Regulated water reclamation and distribution	21,891	17,193	58,142	48,215
Non-regulated energy sales	49,486	40,353	159,575	148,763
Other revenue	15,530	3,205	30,822	13,633
	189,581	151,601	767,593	682,299
Expenses				
Operating	73,221	57,840	211,012	174,853
Regulated electricity purchased	29,250	27,443	100,710	86,348
Regulated gas purchased	10,017	13,761	168,338	186,237
Non-regulated energy purchased	5,270	6,733	22,645	32,797
Administrative expenses	8,482	8,192	27,460	24,165
Depreciation of property, plant and equipment (note 1)	32,914	27,611	100,314	79,325
Amortization of intangible assets	1,446	1,259	3,903	3,410
Other amortization	313	1,665	3,674	2,329
Gain on foreign exchange	(1,635)	(491)	(2,921)	(1,422)
	159,278	144,013	635,135	588,042
Operating income from continuing operations	30,303	7,588	132,458	94,257
Interest expense	15,407	15,928	48,567	48,282
Interest, dividend, equity-method investment and other income	(2,344)	(1,683)	(6,329)	(6,237)
Other gains	(602)	—	(3,011)	—
Acquisition-related costs	605	448	1,363	945
Write-down and loss on disposition of long-lived assets	1,485	7,180	1,757	7,845
Loss (gain) on derivative financial instruments (note 20(b)(iv))	221	(1,635)	(2,236)	(655)
	14,772	20,238	40,111	50,180
Earnings from continuing operations before income taxes	15,531	(12,650)	92,347	44,077
Income tax expense (recovery) (note 15)				
Current	2,123	2,200	6,519	5,940
Deferred	955	(6,737)	25,433	7,203
	3,078	(4,537)	31,952	13,143
Earnings (loss) from continuing operations	12,453	(8,113)	60,395	30,934
Loss from discontinued operations, net of tax (note 18(c))	(241)	(214)	(954)	(646)
Net earnings (loss)	12,212	(8,327)	59,441	30,288
Net loss attributable to non-controlling interests (note 14)	(4,242)	(2,017)	(20,051)	(13,852)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 16,454	$ (6,310)	$ 79,492	$ 44,140
Series A and D Preferred shares dividend (note 12)	2,600	2,600	7,800	6,903
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	$ 13,854	$ (8,910)	$ 71,692	$ 37,237
Basic net earnings (loss) per share from continuing operations (note 16)	$ 0.06	$ (0.04)	$ 0.29	$ 0.18
Basic net earnings (loss) per share (note 16)	0.05	(0.04)	0.29	0.18
Diluted net earnings (loss) share from continuing operations (note 16)	0.06	(0.04)	0.28	0.18
Diluted net earnings (loss) per share (note 16)	$ 0.05	$ (0.04)	$ 0.28	$ 0.18

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,	
	2015	2014	2015	2014
Net earnings/(loss)	$ 12,212	$ (8,327)	$ 59,441	$ 30,288
Other comprehensive income:				
Foreign currency translation adjustment, net of tax of $Nil (2014 - tax recovery $229 and $25) (note 20(b)(iii))	104,137	60,093	227,555	65,483
Change in fair value of cash flow hedge, net of tax of $6,790 and $13,199 (2014 - $8,499 and tax recovery of $273) (note 20(b)(ii))	10,793	12,474	18,733	(6,612)
Unrealized change in value of available-for-sale investments	(164)	244	(165)	1
Change in pension and other post-employment benefits, net of tax of $134 and $3,221 (2014 - $3 and $nil) (note 8)	207	(242)	4,969	(739)
Other comprehensive income, net of tax	114,973	72,569	251,092	58,133
Comprehensive income	127,185	64,242	310,533	88,421
Comprehensive income attributable to the non-controlling interests	18,707	12,927	27,106	4,237
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$ 108,478	$ 51,315	$ 283,427	$ 84,184

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, 2015

	Algonquin Power & Utilities Corp. Shareholders							
	Common shares	**Preferred shares**	**Subscription receipts**	**Additional paid-in capital**	**Accumulated deficit**	**Accumulated OCI**	**Non-controlling interests**	**Total**
Balance, December 31, 2014	$1,633,262	$213,805	$ 110,503	$ 33,068	$ (505,305)	$ 34,213	$316,842	$1,836,388
Net earnings (loss)	—	—	—	—	79,492	—	(20,051)	59,441
Redeemable non-controlling interests not included in equity	—	—	—	—	—	—	2,755	2,755
Other comprehensive income	—	—	—	—	—	203,935	47,157	251,092
Dividends declared and distributions to non-controlling interests	—	—	—	—	(78,236)	—	(1,906)	(80,142)
Dividends and issuance of shares under dividend reinvestment plan	20,354	—	—	—	(20,354)	—	—	—
Contributions received from non-controlling interests	—	—	—	—	—	—	10,815	10,815
Shares issued pursuant to public offering, net of costs	(274)	—	—	—	—	—	—	(274)
Issuance of common shares under share-based compensation plan	1,018	—	—	(282)	(60)	—	—	676
Share-based compensation	—	—	—	3,727	—	—	—	3,727
Balance, September 30, 2015	$1,654,360	$213,805	$ 110,503	$ 36,513	$ (524,463)	$ 238,148	$355,612	$2,084,478

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, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Cash provided by (used in):				
Operating Activities				
Net earnings (loss) from continuing operations	$ 12,453	$ (8,113)	$ 60,395	$ 30,934
Adjustments and items not affecting cash:				
Depreciation of property, plant and equipment	32,914	27,611	100,314	79,325
Amortization of intangible assets	1,446	1,259	3,903	3,410
Other amortization	1,886	(74)	5,415	1,534
Deferred taxes	955	(6,737)	25,433	7,203
Unrealized loss (gain) on derivative financial instruments	(345)	(2,305)	(3,150)	1,659
Share-based compensation	1,813	1,222	3,727	2,054
Cost of equity funds used for construction purposes	(557)	(309)	(1,654)	(1,316)
Pension and post-employment expense (income)	(77)	(1,435)	465	(2,311)
Deferred insurance proceeds and revenue amortization	1,483	—	862	—
Write-down and loss on disposal of long-lived assets	1,654	7,180	2,399	8,171
Changes in non-cash operating items (note 19)	22,931	(21,355)	(28,886)	(34,395)
Changes in non-cash operating items from discontinued operations	—	261	—	770
Cash used in discontinued operations	(400)	(328)	(1,684)	(781)
	76,156	(3,123)	167,539	96,257
Financing Activities				
Cash dividends on common shares	(20,685)	(13,815)	(59,043)	(41,057)
Cash dividends on preferred shares	(2,600)	(2,600)	(7,800)	(6,903)
Cash contributions from non-controlling interests	—	—	22	—
Production based cash contributions from non-controlling interest	—	—	10,815	8,976
Cash distributions to non-controlling interests	(933)	(332)	(2,048)	(3,818)
Issuance of common shares, net of costs	335	165,521	820	165,800
Issuance of preferred shares, net of costs	—	—	—	96,274
Increase in long-term liabilities	117,897	606,977	315,265	1,279,527
Decrease in long-term liabilities	(8,549)	(624,571)	(101,660)	(1,169,998)
Increase in other long-term liabilities	3,123	3,311	7,071	3,834
Decrease in other long-term liabilities	(1,466)	—	(3,548)	—
	87,122	134,491	159,894	332,635
Investing Activities				
Increase in other assets	(13,697)	(1,662)	(7,724)	(4,658)
Distributions received (paid) in excess of equity income	911	188	769	(24)
Proceeds from sale of discontinued operations	—	—	—	20,826
Receipt of principal on notes receivable	168	73	2,988	229
Additions to property, plant and equipment	(80,031)	(111,289)	(161,877)	(290,665)
Acquisitions of long-term investments	(52,503)	(1,451)	(123,159)	(12,057)
Acquisitions of operating entities	—	—	(3,717)	(8,845)
Acquisitions of non-controlling interests	—	—	—	(127,260)
Proceeds from sale of long-lived assets	5,516	5,709	5,516	5,709
	(139,636)	(108,432)	(287,204)	(416,745)
Effect of exchange rate differences on cash	2,126	294	2,548	616
Increase in cash and cash equivalents	25,768	23,230	42,777	12,763
Cash and cash equivalents, beginning of the period	26,282	3,372	9,273	13,839
Cash and cash equivalents, end of the period	$ 52,050	$ 26,602	$ 52,050	$ 26,602
Supplemental disclosure of cash flow information:				
Cash paid during the year for interest expense	$ 25,128	$ 23,163	$ 59,896	$ 51,519
Cash paid during the year for income taxes	$ 1,437	$ 237	$ 5,321	$ 1,588
Non-cash financing and investing activities:				
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	$ 8,311	$ 4,186	$ 21,372	$ 12,367
Property, plant and equipment acquisitions in accruals as at balance sheet date	$ 24,279	$ 17,645	$ 24,279	$ 17,645

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 is a diversified generation, transmission and distribution utility company. The distribution business group operates in the United States under the name of Liberty Utilities Co. ("Distribution Group") and provides rate regulated water, electricity and natural gas utility services. The generation business group operates under the name Algonquin Power Co. ("Generation Group") and owns or has interests in a portfolio of non-regulated North American based contracted wind, solar, hydroelectric and natural gas powered generating facilities. The transmission business group operates under the name Liberty Utilities (Pipeline & Transmission) ("Transmission Group") and invests in rate regulated electric transmission and natural gas pipeline systems in the United States and Canada.

1. Significant accounting policies

Basis of preparation

The accompanying unaudited interim consolidated financial statements and accompanying 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 Securities and Exchange Commission ("SEC").

The significant accounting policies applied to these unaudited interim consolidated financial statements of APUC are consistent with those disclosed in the audited consolidated financial statements of APUC for the year ended December 31, 2014 except for adopted accounting policies described below and in note 2(a).

Individual components of a wind facility are recorded and depreciated separately in the books and records of the Company. Effective January 1, 2015, the Company changed the depreciation method from the straight-line method to the unit-of-production method for certain components of its wind generating facilities where the useful life of the component is directly related to the amount of production. The benefits of components that are subject to wear and tear from the power generation process are best reflected through the unit-of-production method. The Company generally uses wind studies prepared by third parties to estimate the total expected production of each component. This change in the depreciation method results from having better information on the consumption of the benefits of certain components that are directly related to production. The change is being recognized prospectively. The impact of the change on the operating results for the three and nine months period ended September 30, 2015 was a reduction of depreciation expense of $3,334 and $4,250, respectively. The impact on basic and diluted net earnings per share for the three and nine months ended September 30, 2015 was an increase of $0.01 and $0.02, respectively. The change is not expected to materially affect net earnings or net earnings per share on an annual basis.

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

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

The FASB issued ASU 2015-13 Derivatives and Hedging (Topic 815): Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets. This ASU clarifies that that the use of locational marginal pricing by an independent system operator does not constitute net settlement of a contract for the purchase or sale of electricity on a forward basis that necessitates transmission through, or delivery to a location within, a nodal energy market. Consequently, the use of locational marginal pricing by the independent system operator does not cause that contract to fail to meet the physical delivery criterion of the normal purchases and normal sales scope exception. The adoption of this ASU in the third quarter of 2015 had no impact on the Company's unaudited interim consolidated financial statements.

The FASB issued ASU 2015-10, Technical Corrections and Improvements, to clarify the codification, correct unintended application of guidance, or make minor improvements to the codification. The adoption of this ASU in the second quarter of 2015 had no impact on the Company's unaudited interim consolidated financial statements.

The FASB issued ASU 2015-04, Compensation: Retirement Benefits (Subtopic 715), to provide a practical expedient that permits an entity with a fiscal year-end that does not coincide with a month-end and an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan assets and obligations to measure defined benefit plan assets and obligations using the month-end that is closest to the entity’s fiscal year-end or significant event. The Company adopted this ASU prospectively in the second quarter of 2015 and as a result, remeasured amendments to its pension plans, made during the second quarter, using the month-end closest to the amendments (note 8).

The FASB issued ASU 2015-03, Interest: Imputation of Interest (Subtopic 835-30), to simplify presentation of debt issuance costs. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected. Effective January 1, 2015, the Company applied this ASU retrospectively to all prior periods presented in the financial statements. As a result, deferred financing costs of $8,304 as of December 31, 2014 that were previously presented as Other assets on the consolidated balance sheets have been reclassified as a deduction from the carrying amount of the related long-term liabilities. In accordance with ASU 2015-15 Interest: Imputation of Interest (Subtopic 835-30) the Company will continue to present deferred issuance costs related to its revolving credit facilities and related instruments as Other assets.

The FASB issued ASU 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This newly issued accounting standard raises the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. Effective January 1, 2015, the Company adopted this ASU prospectively and as a result, its adoption had no impact on discontinued operations reported in prior periods.

(b) Recent accounting guidance not yet adopted

The FASB issued ASU 2015-16 Business Combinations (Topic 805): Simplifying the Accounting for Measurement Period Adjustments. Under this ASU, adjustments to the provisional amounts recorded in a business combination continue to be calculated as if the accounting had been completed at the acquisition date. However, the ASU eliminates the requirement to retrospectively account for those adjustments and instead requires recognition in the period that the adjustments are identified. The amendments in this ASU should be applied prospectively to adjustments to provisional amounts that occur after December 15, 2015 with earlier application permitted for financial statements that have not been issued. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

2. Recently issued accounting pronouncements (continued)

(b) Recent accounting guidance not yet adopted (continued)

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 prospective application of this standard is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2015-05, Intangibles: Goodwill and Other Internal-Use Software (Subtopic 350-40), to provide guidance to customers about whether a cloud computing arrangement includes a software license. This ASU can be adopted either (1) prospectively to all arrangements entered into or materially modified after the effective date or (2) retrospectively. The standard is effective for fiscal years and interim periods beginning after December 15, 2015. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis, which ends the deferral granted to investment companies from applying the VIE guidance and makes targeted amendments to the current consolidation guidance. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the VIE characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. This ASU may be applied using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the fiscal year of adoption or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2015-01, Income Statement: Extraordinary and Unusual Items (Subtopic 225-20), to simplify income statement classification by removing the concept of extraordinary items from U.S. GAAP. As a result, items that are both unusual and infrequent will no longer be separately reported net of tax after continuing operations. This ASU may be applied prospectively or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. Early adoption is permitted, but only as of the beginning of the fiscal year of adoption. The adoption of this standard is not expected to have an impact on the Company's results of operations.

The FASB issued ASU 2014-16, Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share is More Akin to Debt or to Equity. ASU No. 2014-16 clarifies how current guidance should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. In addition, ASU 2014-16 clarifies that in evaluating the nature of a host contract, an entity should assess the substance of the relevant terms and features (that is, the relative strength of the debt-like or equity-like terms and features given the facts and circumstances) when considering how to weigh those terms and features. The effects of initially adopting ASU 2014-16 should be applied on a modified retrospective basis to existing hybrid financial instruments issued in a form of a share as of the beginning of the fiscal year for which the amendments are effective. Retrospective application is permitted to all relevant prior periods. ASU 2014-16 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2014-15, Presentation of Financial Statements — Going Concern. This new standard provides that in connection with preparing financial statements for each annual and interim reporting period, an entity’s management should evaluate whether there are conditions or events, that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the date that the financial statements are issued. This ASU will be effective for the annual reporting period ending after December 15, 2016, and for annual and interim periods thereafter. Early application is permitted. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

2. Recently issued accounting pronouncements (continued)

(b) Recent accounting guidance not yet adopted (continued)

The FASB issued ASU 2014-12, Compensation-Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period. This newly issued accounting standard is intended to resolve the diverse accounting treatment of those awards in practice. This ASU is required to be applied for fiscal years and interim periods beginning after December 15, 2015. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB and the International Accounting Standards Board have jointly issued a new revenue recognition standard codified in U.S. GAAP as ASU 2014-09, Revenue from Contracts with Customers (Topic 606). 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. During the quarter, the FASB approved a one year deferral of the effective date of this new revenue standard and as such, it is now 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 is currently assessing the impact the adoption of this standard might have on its financial position or results of operations.

3. Business acquisitions and development projects

(a) Acquisition of New Hampshire Gas

On January 2, 2015, the Distribution Group completed the acquisition of New Hampshire Gas, a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System services approximately 1,200 propane gas distribution customers. Total purchase price for the New Hampshire Gas System is U.S. $3,161.

(b) Agreement to acquire Park Water System

On September 19, 2014, the Company entered into an agreement to acquire the regulated water distribution utility Park Water Company (“Park Water System”). Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Total consideration for the utility purchase is expected to be approximately U.S. $327,000, which includes the assumption of approximately U.S. $77,000 of existing long-term utility debt and is subject to certain working capital and other closing adjustments. Required state and federal regulatory approvals are expected in late 2015.

(c) Development of Bakersfield Solar Facility

In 2014, the Company completed construction of a 20 MWac solar powered generating facility located in Kern County, California and the facility was placed in service on December 31, 2014. The Company invested U.S $56,726 in the development and construction of the solar energy facility which is recorded as property, plant and equipment. The facility achieved commercial operation under the power purchase agreement on April 14, 2015 and started selling power at the power purchase agreement price on May 15, 2015. The weighted average useful life of the Bakersfield Solar Facility is 35 years.

On August 13, 2014, the Generation Group entered into a partnership agreement with a third-party (the "Tax Investor"). To date the Tax investor has funded U.S. $11,201and is expected to fund an additional amount of approximately U.S. $11,500 in late 2015 or early 2016. With its partnership interest, the Tax Investor will receive the majority of the tax attributes associated with the facility. The Tax Equity investment net of non-controlling interest earned as of September 30, 2015 is U.S. $8,193.

Under certain conditions, the Tax Investor has the right to withdraw from the Bakersfield Solar Facility and require the Company to redeem its interests for cash over a contractual payment period. As a result, the Company accounts for this interest as temporary equity outside of permanent equity on the consolidated balance sheets as "Redeemable non-controlling interest".

3. Business acquisitions and development projects (continued)

(c) Development of Bakersfield Solar Facility (continued)

At each balance sheet date, the Company will reevaluate the classification of its redeemable instrument, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company will record the instruments at its redemption value. Increases or decreases in the carrying amount of a redeemable instrument will be recorded within accumulated deficit. Redemption is not considered probable as of September 30, 2015.

(d) Commercial operation of Morse Wind Facility

In 2015, the Company completed construction of a 23 MW wind generating facility located near Morse, Saskatchewan. The Company invested $65,056 in the development and construction of the wind facility which is recorded as property, plant and equipment, as well as additional amounts related to development rights and other intangibles, for a total investment of $81,765. Sale of power to the utility commenced in March 2015 at rates equivalent to those under the power purchase agreement. Commercial operations date as defined in the power purchase agreement occurred on April 22, 2015. The weighted average useful life of the Morse Wind Facility is 32 years.

4. Accounts receivable

Accounts receivable as of September 30, 2015 include unbilled revenue of $19,811 (December 31, 2014 - $52,880) from the Company's regulated utilities. Accounts receivable as of September 30, 2015 are presented net of allowance for doubtful accounts of $8,003 (December 31, 2014 - $7,229).

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 FASB ASC 980 Regulated Operations ("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 revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate-setting process.

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

In December 2014, the Peach State Gas System received a Final Order from the Georgia Public Service approving an annual revenue increase of U.S. $3,680 in connection with its annual GRAM filing. The new rates are effective as of February 1, 2015.

In December 2014, the Midstates Gas System received a Final Order from the Missouri Public Service Commission approving an annual revenue increase of U.S. $4,868. The new rates are effective as of January 2, 2015.

In February 2015, the Midstates Gas System received a Final Order from the Illinois Commerce Commission approving an annual revenue increase of U.S. $4,625. The new rates are effective as of February 20, 2015.

In March 2015, the Pine Bluff System received a Final Order from the Arkansas Public Service Commission approving an annual revenue increase of U.S. $1,087. The new rates are effective as of March 15, 2015.

In June 2015, the EnergyNorth Natural Gas System received a Final Order from the New Hampshire Public Utilities Commission approving a rate increase of U.S. $12,400 consisting of U.S. $10,500 in annual delivery revenue and an additional U.S. $1,900 for incremental capital expended after the test year. The new rates were effective as of July 1, 2015 for service rendered on and after November 1, 2014.

5. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

	September 30, 2015	December 31, 2014
Regulatory assets		
Environmental costs	**$ 105,808**	$ 102,735
Pension and post-employment benefits	**70,358**	65,745
Storm costs	**—**	2,050
Commodity costs adjustment	**8,120**	41,502
Rate case costs	**5,620**	4,161
Vegetation management	**3,269**	3,260
Debt premium	**5,216**	4,658
Rate adjustment mechanism	**14,689**	6,207
Asset retirement obligation	**2,002**	1,682
Tax related	**5,853**	4,350
Other	**13,347**	13,155
Total regulatory assets	**$ 234,282**	$ 249,505
Less current regulatory assets	**(26,600)**	(61,645)
Non-current regulatory assets	**$ 207,682**	$ 187,860
Regulatory liabilities		
Cost of removal	**$ 91,702**	$ 78,013
Rate-base offset	**24,465**	23,427
Commodity costs adjustment	**24,981**	10,389
Depreciation adjustment mechanism	**3,340**	3,518
Other	**6,451**	6,409
Total regulatory liabilities	**$ 150,939**	$ 121,756
Less current regulatory liabilities	**(35,084)**	(20,590)
Non-current regulatory liabilities	**$ 115,855**	$ 101,166

6. Long-term investments

Long-term investments consist of the following:

	September 30, 2015	December 31, 2014
Equity-method investees		
50% interest in Odell Wind Project Joint Venture (a)	**$ 5,927**	$ 2,267
2.5% interest in Northeast Expansion LLC	**2,910**	1,063
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	**612**	1,512
50% interest in the Valley Power Partnership	**1,229**	1,253
Other	**1,395**	503
	$ 12,073	$ 6,598
Available-for-sale investment	**$ 2,854**	$ 137
Notes receivable		
Development loans (a)	**$ 142,965**	$ 17,582
Red Lily Senior loan, interest at 6.31%	**11,588**	11,588
Red Lily Subordinated loan, interest at 12.5%	**6,565**	6,565
Chapais Énergie, Société en Commandite interest at 10.789%	**170**	649
Silverleaf resorts loan, interest at 15.48% maturing July 2020	**2,696**	2,344
Other	**1,721**	782
	165,705	39,510
Total long-term investments	**180,632**	46,245
Less current portion	**(35,095)**	(2,966)
Non-current long-term investments	**$ 145,537**	$ 43,279

(a) Odell Wind Project Joint Venture

In 2014, the Company acquired a 50% equity interest in Odell SponsorCo LLC ("Odell SponsorCo") which indirectly owns a 200 MW wind development project ("Odell Wind Project") in the state of Minnesota. The total construction costs of the Odell Wind Project are estimated to be U.S. $322,766. The Company holds an option to acquire the other 50% interest of Odell SponsorCo for total contributions, subject to certain adjustments, within 30 days of commencement of operations which is expected in 2016. In 2015, the Company advanced U.S. $93,971 to the project for a total advance of U.S. $107,130 as at September 30, 2015. The Company also provides credit support to the project. In 2015, the Company issued a U.S. $1,119 letter of credit on behalf of the project pursuant to the generator interconnection agreement.

Subsequent to quarter end, on October 6, 2015, U.S. $23,800 of loans from each investor were converted into common equity in Odell SponsorCo. The Company also provided guarantee of Odell SponsorCo's obligations under the equity capital contribution agreement and limited liability company agreement.

(b) Deerfield Wind Project Joint Venture

Subsequent to quarter end, on October 15, 2015, the Company acquired 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. The total construction costs of the Deerfield Wind Project are estimated to be U.S. $303,000.

6. Long-term investments (continued)

(b) Deerfield Wind Project (continued)

Upon the acquisition of the Deerfield Wind Project by Deerfield SponsorCo, the two members each contributed U.S. $1,000 to the capital of Deerfield SponsorCo. Upon execution of third-party construction loan and tax equity documents expected in 2016, each party will contribute another U.S. $18,596 plus accrued interest at 7% to the capital of Deerfield SponsorCo. The Company holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments within 90 days of commencement of operations, which is expected in late 2016.

The Company entered into a loan and credit support facility with Deerfield SponsorCo. During construction, the Company has committed to provide Deerfield SponsorCo 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 Deerfield Wind Project. The following credit support was issued by the Company on or about October 19, 2015: guarantee of the obligations of the Deerfield Wind Project under the wind turbine supply agreement, engineering, procurement and construction agreement, power purchase agreement, and decommissioning plan; and, a U.S. $43,238 letter of credit and guarantee of the obligations of Deerfield SponsorCo, to the vendor under the membership interest purchase and contribution agreement.

7. Long-term liabilities

Long-term liabilities consist of the following:

	September 30, 2015	December 31, 2014
Corporate		
$ 65,000 Revolving unsecured credit facility	**$ 18,747**	$ —
Generation Group		
$350,000 Revolving unsecured credit facility	**155,262**	23,400
$485,000 Algonquin Power Co.- Senior unsecured notes	**481,852**	481,438
$ 35,152 Long Sault Hydro Facility - Senior debt	**35,072**	35,997
$ 2,705 Chuteford Hydro Facility - Senior debt	**2,700**	3,022
U.S. $76,000 Shady Oaks Wind Facility - Senior debt	**—**	88,168
Distribution Group		
U.S. $200,000 Revolving unsecured credit facility	**—**	23,898
U.S. $525,000 Liberty Utilities Co. - Senior unsecured notes	**695,645**	419,876
U.S. $70,000 Calpeco Electric System - Senior unsecured notes	**92,549**	80,368
U.S. $50,000 Liberty Water Co - Senior unsecured notes	**66,000**	57,301
U.S. $19,500 New England Gas System - First mortgage bonds	**31,248**	27,288
U.S. $15,000 Granite State Electric System - Senior unsecured notes	**19,988**	17,373
U.S. $ 9,800 LPSCo Water System - IDA bonds	**13,078**	12,441
U.S. $ 890 Bella Vista Water System - Loans	**1,188**	1,149
	$ 1,613,329	$ 1,271,719
Less current portion	**(21,719)**	(9,130)
	$ 1,591,610	$ 1,262,589

7. Long-term liabilities (continued)

Effective January 1, 2015, the Company applied ASU 2015-03 (note 2(a)) retrospectively to all prior periods presented in the financial statements. As a result, deferred financing costs of $8,304 as of December 31, 2014 that were previously presented as Other assets on the consolidated balance sheets have been reclassified as a deduction from the carrying amount of the related long-term liabilities in the table above.

On April 30, 2015, the Distribution Group issued U.S. $160,000 of senior unsecured 30 year notes bearing a coupon of 4.13% via a private placement in the U.S. The proceeds of the financing will be used in connection with the acquisition of the Park Water System and for general corporate purposes. The funds are being drawn in two tranches: U.S. $90,000 was drawn immediately on closing and U.S. $70,000 was drawn on July 15, 2015.

On May 12, 2015, the U.S. $76,000 senior debt for the Shady Oaks Wind Facility was repaid.

On May 27, 2015, the Generation Group extended the maturity of its senior unsecured credit facility one year to July 31, 2019 with all other terms remaining the same.

Subsequent to quarter end, on October 1, 2015, the U.S. $9,800 LPSCo Water System IDA bonds were fully repaid. As at September 30, 2015 the debt is presented as a current liability and the funds used for repayment are classified as current restricted cash under Other assets.

On October 30 2015, the Generation Group entered into a new extendible one year letter of credit facility agreement. The new facility expands the group's available liquidity by providing for issuances of letters of credit up to a maximum of $50,000 and U.S. $30,000. Certain letters of credit issued on the existing Generation credit facility will be transferred to the new facility.

8. Pension and other post-employment benefits

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

	Pension benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	**2015**	2014
Service cost	**$ 1,595**	$ 1,270	**$ 4,729**	$ 3,878
Interest cost	**2,420**	1,992	**6,946**	6,081
Expected return on plan assets	**(3,129)**	(2,417)	**(8,854)**	(7,375)
Amortization of net actuarial loss (gain)	**323**	(82)	**923**	(252)
Amortization of prior service costs	**(161)**	—	**(324)**	—
Amortization of net regulatory assets/liabilities	**1,151**	485	**3,358**	1,482
Net benefit cost	**$ 2,199**	$ 1,248	**$ 6,778**	$ 3,814

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

	OPEB			
	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Service cost	**$ 758**	$ 514	**$ 2,191**	$ 1,568
Interest cost	**697**	527	**2,015**	1,608
Expected return on plan assets	**(199)**	(154)	**(576)**	(469)
Amortization of net actuarial loss (gain)	**35**	(154)	**100**	(469)
Amortization of net regulatory assets/liabilities	**272**	43	**780**	129
Net benefit cost	**$ 1,563**	$ 776	**$ 4,510**	$ 2,367

On February 6, 2015, the Company permanently froze the accrual of retirement benefits for most non-union participants under existing plans, effective March 31, 2015. Subsequent to the effective date, these employees began accruing benefits under the Company's cash balance plan. The plan amendment resulted in a decrease to the projected benefit obligation of U.S. $2,750 which is recorded as a prior service credit in other comprehensive income ("OCI"). In conjunction with the plan amendment, the assets and projected benefit obligations of amended plans were revalued as at February 6, 2015 which resulted in an actuarial loss of U.S. $3,246 recorded in OCI.

On April 17, 2015, and May 6, 2015 the Company permanently froze the accrual of retirement benefits for most union participants under existing plans, effective December 31, 2015. Subsequent to the effective date, these employees will begin accruing benefits under the Company's cash balance plan. The plan amendment resulted in a decrease to the projected benefit obligation of U.S. $1,191 which is recorded as a prior service credit in other comprehensive income ("OCI"). In conjunction with the plan amendment, the Company adopted ASU 2015-04 (note 2(a)) which allowed the assets and projected benefit obligations of amended plans to be revalued at the closest month-end date of April 30, 2015 which resulted in an actuarial gain of U.S. $5,244 recorded in OCI.

9. Other long-term liabilities

Other long-term liabilities consist of the following:

	September 30, 2015	December 31, 2014
Advances in aid of construction	**$ 89,156**	$ 81,104
Environmental obligation	**66,280**	72,305
Deferred tax credit (note 15)	**5,589**	19,130
Deferred insurance proceeds	**10,436**	12,191
Asset retirement obligation	**16,971**	13,884
Other	**40,217**	30,157
	228,649	228,771
Less current portion	**(43,184)**	(49,303)
	$ 185,465	$ 179,468

10. Shareholders' capital

(a) Common shares

Number of common shares:

	2015
Common shares, beginning of year	**238,149,468**
Issuance of shares under the dividend reinvestment and employee share-based compensation plans	**2,337,376**
Common shares, end of period	**240,486,844**

(b) Share-based compensation

On May 19, 2015 the Board Approved the grant of 1,608,974 options to executives of the Company. The options allow for the purchase of common shares at a price of $9.76, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2016, 2017, and 2018. Options may be exercised up to eight years following the date of grant.

During the nine months ended September 30, 2015, 33,877 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.

During the second quarter, the Company settled 41,131 vested Performance Share Units ("PSU") by issuing 22,899 shares from treasury, with the balance withheld for income taxes.

During the second quarter, the Board approved 178,810 PSUs to executives and employees of the Company with most of the awards vesting on December 31, 2017.

For the three and nine months ended September 30, 2015, APUC recorded $1,572 and $3,661 (2014 - $1,130 and $2,122) 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, 2015, total unrecognized compensation costs related to non-vested options and performance share unit were $4,103 and $2,455, respectively, and are expected to be recognized over a period of 1.88 years and 1.75, respectively.

11. Accumulated other comprehensive income (loss)

Accumulated other comprehensive income (loss) consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain (loss) on cash flow hedges	Net change on available-for-sale investments	Pension and post-employment actuarial changes	Total
Balance, January 1, 2014	$ (57,471)	$ 11,840	$ —	$ 14,221	$ (31,410)
OCI before reclassifications	68,938	3,358	519	(35,396)	37,419
Amounts reclassified	—	5,423	(518)	(273)	4,632
Net current period OCI (loss)	68,938	8,781	1	(35,669)	42,051
Acquisition of non-controlling interest	21,029	2,543	—	—	23,572
Balance, December 31, 2014	$ 32,496	$ 23,164	$ 1	$ (21,448)	$ 34,213
OCI (loss) before reclassifications	180,398	21,843	(165)	4,547	206,623
Amounts reclassified	—	(3,110)	—	422	(2,688)
Net current period OCI (loss)	180,398	18,733	(165)	4,969	203,935
Balance, September 30, 2015	$ 212,894	$ 41,897	$ (164)	$ (16,479)	$ 238,148

Amounts reclassified from accumulated other comprehensive income (loss) ("AOCI") for unrealized gain (loss) on cash flow hedges affected revenue from non-regulated energy sales while those for pension and post-employment actuarial changes affected operating expenses.

12. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. For the three months and nine months ended September 30, 2015 , the Company declared dividends to shareholders on common shares totaling $32,554 and $90,604, respectively (2014 - $22,286 and $57,503).

The Board declared a dividend on the Company's common shares of U.S. $0.09625 or $0.1289 per share payable on October 15, 2015 to the shareholders of record on September 30, 2015.

For the three and nine months ended September 30, 2015, the Company declared and paid dividends to Series A preferred shareholders totaling $1,350 and $4,050, respectively (2014 - $1,350 and $4,050) or $0.2813 and $0.8438, respectively, per Series A preferred share (2014 - $0.2813 and $0.8438 per Series A preferred share).

For the three and nine months ended September 30, 2015, the Company declared and paid dividends to Series D preferred shareholders totaling $1,250 and $3,750, respectively (2014 - $1,250 and $2,853) or $0.3125 and $0.9375, respectively, per Series D preferred share (2014 - $0.3125 and $0.7132 per Series D preferred share).

13. Related party transactions

A member of the Board of Directors of APUC is an executive at Emera. For the three and nine months ended September 30, 2015, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), and Bangor Hydro ("BH") subsidiaries of Emera, amounting to U.S. $1,718 and U.S. $5,262, respectively (2014 - U.S. $1,964 and U.S. $8,156). For the three and nine months ended September 30, 2015, Liberty Utilities purchased natural gas amounting to U.S. $Nil and U.S. $1,339 , respectively (2014 - U.S. $149 and U.S. $4,891) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process the results of which were approved by the regulator in the relevant jurisdiction.

There were no amounts outstanding related to these transactions at the end of the periods.

As at September 30, 2015, $nil (December 31, 2014 - $47) was due from Algonquin Power Systems Ltd., a corporation partially owned by Ian Robertson and Chris Jarratt (collectively "Senior Executives").

13. Related party transactions (continued)

Chartered Aircraft

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into a block time agreement to charter aircraft in which Senior Executives have a partial ownership. The Company terminated the agreement effective June 28, 2015 and paid a usage shortfall fee of $13. During the three and nine months ended September 30, 2015, APUC reimbursed direct costs in connection with the use of the aircraft prior to termination of the block time agreement of $172 and $569 (2014 - $137 and $436).

Office Facilities

Until the fourth quarter of 2014 APUC had leased its head office facilities from an entity partially owned by Senior Executives. During the fourth quarter of 2014, APUC terminated the related party lease and moved all head office employees into new premises owned by the Company. Base lease costs for the three and nine months ended September 30, 2015 were $nil (2014 - $90 and $267).

Other

A spouse of one of the Senior Executives was employed to provide market research services to certain subsidiaries of the Company. During the three and nine months ended September 30, 2015 APUC paid $Nil and $20 (2014 - $67 and $141) in relation to these services. The spouse is no longer employed by the Company.

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction is expected to be settled by the end of 2015 or in early 2016.

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

14. Non-controlling interests

Net loss attributable to non-controlling interests consist of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	**2015**	2014
Net earnings attributable to Class B partnership units of Wind Portfolio SponsorCo	**$ —**	$ —	**$ —**	$ 3,483
Net loss attributable to Class A partnership units	**(4,501)**	(2,350)	**(21,372)**	(18,325)
Other net earnings attributable to non-controlling interests	**259**	333	**1,321**	990
Total net loss attributable to non-controlling interests	**$ (4,242)**	$ (2,017)	**$ (20,051)**	$ (13,852)

On March 31, 2014, the Company acquired the remaining Class B partnership units of Wind Portfolio SponsorCo from the non-controlling interest holder. As a result of the transaction, the Company now owns 100% of Wind Portfolio SponsorCo's Class B partnership units.

15. Income taxes

For the nine months ended September 30, 2015, the Company's overall effective tax rate was different from the statutory rate of 26.50% (2014 - 26.50%) due primarily to higher tax rates in U.S. subsidiaries, non-controlling interest partner's tax expenses, inter-corporate dividends, recognition of deferred credits and non-deductible expenses.

On June 26, 2015, the Company entered into an agreement with the Canada Revenue Agency ("CRA") regarding a CRA's proposal to reassess APUC's 2009 through 2013 income tax filings in relation to a unit exchange transaction that occurred on October 27, 2009. The agreement resulted in a $16,042 reduction in the APUC's deferred tax assets and a proportional reduction of $13,333 in its deferred credits. Consequently, the Company's results for the nine months ended September 30, 2015 reflect a $2,709 net non-cash charge to deferred income tax expense.

16. 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 and subscription receipts; additional shares issued subsequent to the balance sheet date under the dividend reinvestment plan; PSUs and DSUs outstanding during the period; and, if dilutive, potential incremental common shares issuable upon the exercise of stock options. The dilutive effect of outstanding stock options is reflected in diluted earnings per share by application of the treasury stock method.

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, 2015 are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2015	**2014**	**2015**	**2014**
Net earnings (loss) attributable to common shareholders of APUC	**$ 13,854**	$ (8,910)	**$ 71,692**	$ 37,237
Discontinued operations	**(241)**	(214)	**(954)**	(646)
Net earnings (loss) attributable to common shareholders of APUC from continuing operations - Basic and Diluted	**$ 14,095**	$ (8,696)	**$ 72,646**	$ 37,883
Weighted average number of shares and subscription receipts				
Basic	**252,352,179**	210,791,056	**251,528,726**	208,322,421
Effect of dilutive securities	**3,552,824**	—	**3,392,848**	1,961,278
Diluted	**255,905,003**	210,791,056	**254,921,574**	210,283,699

For the three and nine months ended September 30, 2015, the shares potentially issuable as a result of 1,608,974 and 1,608,974 stock options (2014 – 5,537,127 and 1,786,401) are excluded from this calculation as they are anti-dilutive.

17. Segmented information

The Company's management reporting is aligned under three business units - Generation, Transmission and Distribution. Under Generation, the Company owns or has interests in hydroelectric, solar and wind power facilities which are aggregated as the renewable segment and operates co-generation, steam production and other thermal facilities which are aggregated as the thermal segment. The Distribution reporting segment aggregates the electric, natural gas and water distribution utilities into a single reporting segment. Finally, the Transmission reporting segment, invests in rate regulated electric transmission and natural gas pipeline systems. As a result, APUC has four reporting segments.

The operating segments were aggregated as generation (renewable, thermal), distribution and transmission based on their economic characteristics. The Transmission segment includes the new equity method investment in the Natural Gas Pipeline Development which is not yet significant and as a result is not presented separately in the tables below but grouped within Corporate.

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.

17. Segmented information (continued)

	Three months ended September 30, 2015					
	Generation			Distribution	Corporate	Total
	Renewable	Thermal	Total			
Revenue						
Regulated electricity distribution	$ —	$ —	$ —	$ 53,370	$ —	$ 53,370
Regulated gas distribution	—	—	—	49,304	—	49,304
Regulated water reclamation and distribution	—	—	—	21,891	—	21,891
Non-regulated energy sales	38,141	11,345	49,486	—	—	49,486
Other revenue	2,691	746	3,437	12,093	—	15,530
	40,832	12,091	52,923	136,658	—	189,581
Operating expenses	14,411	2,626	17,037	56,169	15	73,221
Regulated electricity purchased	—	—	—	29,250	—	29,250
Regulated gas purchased	—	—	—	10,017	—	10,017
Non-regulated energy purchased	1,523	3,747	5,270	—	—	5,270
	24,898	5,718	30,616	41,222	(15)	71,823
Administrative expenses	3,481	79	3,560	4,774	148	8,482
Depreciation of property, plant and equipment	11,457	1,755	13,212	18,935	767	32,914
Amortization of intangible assets	962	264	1,226	220	—	1,446
Other amortization	(21)	—	(21)	334	—	313
Gain on foreign exchange	—	—	—	—	(1,635)	(1,635)
Interest expense	5,419	228	5,647	9,358	402	15,407
Interest, dividend, equity-investment and other income	(424)	(23)	(447)	(1,018)	(879)	(2,344)
Other gains	(602)	—	(602)	—	—	(602)
Acquisition-related costs	—	—	—	—	605	605
Write-down and loss on disposition of long-lived assets	25	—	25	1,460	—	1,485
Gain (loss) on derivative financial instruments	594	—	594	—	(373)	221
Earnings from continuing operations before income taxes	$ 4,007	$ 3,415	$ 7,422	$ 7,159	$ 950	$ 15,531
Capital expenditures	$ 21,483	$ 821	$ 22,304	$ 57,374	$ 353	$ 80,031

17. Segmented information (continued)

	Three months ended September 30, 2014					
	Generation			Distribution	Corporate	Total
	Renewable	Thermal	Total			
Revenue						
Regulated electricity distribution	$ —	$ —	$ —	$ 48,606	$ —	$ 48,606
Regulated gas distribution	—	—	—	42,244	—	42,244
Regulated water reclamation and distribution	—	—	—	17,193	—	17,193
Non-regulated energy sales	29,932	10,421	40,353	—	—	40,353
Other revenue	1,527	921	2,448	757	—	3,205
	31,459	11,342	42,801	108,800	—	151,601
Operating expenses	12,087	2,232	14,319	43,506	15	57,840
Regulated electricity purchased	—	—	—	27,443	—	27,443
Regulated gas purchased	—	—	—	13,761	—	13,761
Non-regulated energy purchased	2,757	3,976	6,733	—	—	6,733
	16,615	5,134	21,749	24,090	(15)	45,824
Administrative expenses	3,300	87	3,387	4,255	550	8,192
Depreciation of property, plant and equipment	11,951	1,543	13,494	13,576	541	27,611
Amortization of intangible assets	871	220	1,091	168	—	1,259
Other amortization	69	—	69	1,596	—	1,665
Gain on foreign exchange	—	—	—	—	(491)	(491)
Interest expense	8,421	441	8,862	7,689	(623)	15,928
Interest, dividend, equity-investment and other (income) loss	(524)	209	(315)	(675)	(693)	(1,683)
Acquisition-related costs	—	—	—	—	448	448
Write-down and loss (gain) on disposition of long-lived assets	—	—	—	(6)	7,186	7,180
Gain on derivative financial instruments	(716)	—	(716)	—	(919)	(1,635)
Earnings (loss) from continuing operations before income taxes	(6,757)	2,634	(4,123)	(2,513)	(6,014)	(12,650)
Earnings (loss) from discontinued operations before income taxes	488	(171)	317	—	—	317
Earnings (loss) before income taxes	$ (7,245)	$ 2,805	$ (4,440)	$ (2,513)	$ (6,014)	$ (12,967)
Capital expenditures	$ 61,461	$ 514	$ 61,975	$ 44,990	$ 4,324	$ 111,289

17. Segmented information (continued)

	Nine months ended September 30, 2015					
	Generation			Distribution	Corporate	Total
	Renewable	Thermal	Total			
Revenue						
Regulated electricity distribution	$ —	$ —	$ —	$ 169,526	$ —	$ 169,526
Regulated gas distribution	—	—	—	349,528	—	349,528
Regulated water reclamation and distribution	—	—	—	58,142	—	58,142
Non-regulated energy sales	129,343	30,232	159,575	—	—	159,575
Other revenue	12,311	2,879	15,190	15,632	—	30,822
	141,654	33,111	174,765	592,828	—	767,593
Operating expenses	40,322	8,280	48,602	162,365	45	211,012
Regulated electricity purchased	—	—	—	100,710	—	100,710
Regulated gas purchased	—	—	—	168,338	—	168,338
Non-regulated energy purchased	8,574	14,071	22,645	—	—	22,645
	92,758	10,760	103,518	161,415	(45)	264,888
Administrative expenses	11,461	259	11,720	15,347	393	27,460
Depreciation of property, plant and equipment	39,659	5,103	44,762	53,085	2,467	100,314
Amortization of intangible assets	2,501	762	3,263	640	—	3,903
Other amortization	(61)	—	(61)	3,735	—	3,674
Gain on foreign exchange	—	—	—	—	(2,921)	(2,921)
Interest expense	20,531	814	21,345	26,010	1,212	48,567
Interest, dividend, equity-investment and other income	(1,287)	(171)	(1,458)	(2,992)	(1,879)	(6,329)
Other gains	(3,011)	—	(3,011)	—	—	(3,011)
Acquisition-related costs	—	—	—	—	1,363	1,363
Write-down and loss on disposition of long-lived assets	45	—	45	1,712	—	1,757
Gain on derivative financial instruments	(1,479)	—	(1,479)	—	(757)	(2,236)
Earnings from continuing operations before income taxes	$ 24,399	$ 3,993	$ 28,392	$ 63,878	$ 77	$ 92,347
Property, plant and equipment	$1,749,247	$ 93,835	$1,843,082	$1,814,662	$ 60,331	$ 3,718,075
Equity-method investees	5,965	1,229	7,194	742	4,137	12,073
Total assets	2,149,582	110,025	2,259,607	2,401,054	98,334	4,758,995
Capital expenditures	49,745	1,420	51,165	107,717	2,995	161,877

17. Segmented information (continued)

	Nine months ended September 30, 2014					
	Generation			Distribution	Corporate	Total
	Renewable	Thermal	Total			
Revenue						
Regulated electricity distribution	$ —	$ —	$ —	$ 150,318	$ —	$ 150,318
Regulated gas distribution	—	—	—	321,370	—	321,370
Regulated water reclamation and distribution	—	—	—	48,215	—	48,215
Non-regulated energy sales	114,919	33,844	148,763	—	—	148,763
Other revenue	8,945	2,480	11,425	2,208	—	13,633
	123,864	36,324	160,188	522,111	—	682,299
Operating expenses	35,097	7,410	42,507	132,301	45	174,853
Regulated electricity purchased	—	—	—	86,348	—	86,348
Regulated gas purchased	—	—	—	186,237	—	186,237
Non-regulated energy purchased	15,146	17,651	32,797	—	—	32,797
	73,621	11,263	84,884	117,225	(45)	202,064
Administrative expenses	9,718	256	9,974	13,695	496	24,165
Depreciation of property, plant and equipment	35,954	4,453	40,407	37,372	1,546	79,325
Amortization of intangible assets	2,210	662	2,872	538	—	3,410
Other amortization	69	—	69	2,260	—	2,329
Gain on foreign exchange	—	—	—	—	(1,422)	(1,422)
Interest expense	25,106	1,419	26,525	20,513	1,244	48,282
Interest, dividend, equity-investment and other (income) loss	(1,301)	231	(1,070)	(2,466)	(2,701)	(6,237)
Acquisition-related costs	—	—	—	—	945	945
Write-down and loss on disposition of long-lived assets	—	372	372	287	7,186	7,845
(Gain) loss on derivative financial instruments	(857)	—	(857)	—	202	(655)
Earnings (loss) from continuing operations before income taxes	2,722	3,870	6,592	45,026	(7,541)	44,077
Earnings (loss) from discontinued operations before income taxes	1,204	(127)	1,077	—	—	1,077
Earnings (loss) before income taxes	$ 1,518	$ 3,997	$ 5,515	$ 45,026	$ (7,541)	$ 43,000
Property, plant and equipment	$1,518,796	$ 83,080	$1,601,876	$1,410,517	$ 56,400	$3,068,793
Equity-method investees	—	1,542	1,542	482	1,647	3,671
Total assets	1,648,872	102,886	1,751,758	1,892,471	164,260	3,808,489
Capital expenditures	137,444	3,516	140,960	99,498	50,207	290,665

18. 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, with the exception of those matters described below. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

(i) On October 21, 2011, the Quebec Court of Appeal ordered a subsidiary of APUC to pay approximately $5,400 (including interest) to the Government of Quebec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6,700. In 2012, the Company paid an amount of $1,884 to the government of Quebec in relation to the early years covered by the claim in order to mitigate the impact of accruing interests on any amount ultimately determined to be payable or recoverable.

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 6, the following significant commitments exist as of September 30, 2015.

As a result of the dam safety legislation passed in Quebec (Bill C-93), APUC has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. The assessments have identified a number of remedial measures required to meet the new safety standards. APUC currently estimates further capital expenditures of approximately $8,000 over a period of four years related to compliance with the legislation.

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
Purchased power	$ 95,309	$ 55,250	$ 59,437	$ 64,186	$ 66,147	$108,911	$ 449,240
Gas delivery, service and supply agreements	62,078	46,483	35,130	34,226	33,301	89,938	301,156
Service agreements	35,804	36,444	33,691	34,646	34,855	513,391	688,831
Capital projects	5,154	—	7,500	—	—	—	12,654
Operating leases	6,251	5,278	4,820	4,636	4,649	104,833	130,467
Total	$204,596	$143,455	$140,578	$137,694	$138,952	$817,073	$1,582,348

On April 21, 2015, Calpeco Electric System has entered into an all-purpose power purchase agreement with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2016 and terminates on May 1, 2022. The commitment amounts included in the table above are based on market prices as of September 30, 2015. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

18. Commitments and contingencies

(c) Royalty payment

The loss from discontinued operations in 2015 primarily relates to resolution of a royalty agreement associated with the sale of a small U.S. hydroelectric facility in 2014.

19. 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,	
	2015	**2014**	**2015**	**2014**
Accounts receivable	**$ 9,752**	$ 14,553	**$ 43,995**	$ 36,734
Natural gas in storage	**(11,152)**	(15,179)	**3,716**	(9,294)
Supplies and consumable inventory	**(1,478)**	(979)	**(3,272)**	(1,689)
Income taxes receivable	**216**	(19)	**58**	(20)
Prepaid expenses	**4,299**	4,878	**(4,119)**	2,758
Accounts payable	**(956)**	(4,527)	**(49,395)**	17,185
Accrued liabilities	**27,757**	(4,547)	**(55,343)**	(35,099)
Current income tax liability	**1,321**	1,503	**950**	1,143
Net regulatory assets and liabilities	**(6,828)**	(17,038)	**34,524**	(46,113)
	$ 22,931	$ (21,355)	**$ (28,886)**	$ (34,395)

20. Financial instruments

(a) Fair value of financial instruments

September 30, 2015	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 165,705	$ 171,425	$ —	$ 171,425	$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	88,705	88,705	—	—	88,705
Total derivative financial instruments	88,705	88,705	—	—	88,705
Total financial assets	$ 254,410	$ 260,130	$ —	$ 171,425	$ 88,705
Long-term liabilities	$ 1,613,329	$ 1,717,474	$ 516,487	$ 1,200,987	$ —
Preferred shares, Series C	18,566	17,176	—	17,176	—
Derivative financial instruments:					
Energy contracts not designated as a cash flow hedge	178	178	—	—	178
Cross-currency swap designated as a net investment hedge	84,503	84,503	—	84,503	—
Interest rate swap designated as a hedge	9,355	9,355	—	9,355	—
Commodity contracts for regulated operations	2,665	2,665	—	2,665	—
Total derivative financial instruments	96,701	96,701	—	96,523	178
Total financial liabilities	$ 1,728,596	$ 1,831,351	$ 516,487	$ 1,314,686	$ 178

20. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

December 31, 2014	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 39,510	$ 41,339	$ —	$ 41,339	$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	41,966	41,966	—	—	41,966
Energy contracts not designated as a cash flow hedge	504	504	—	—	504
Total derivative financial instruments	42,470	42,470	—	—	42,470
Total financial assets	$ 81,980	$ 83,809	$ —	$ 41,339	$ 42,470
Long-term liabilities	$1,271,719	$1,363,934	$ 520,142	$ 843,792	$ —
Preferred shares, Series C	18,693	18,209	—	18,209	—
Derivative financial instruments:					
Cross-currency swap designated as a net investment hedge	36,276	36,276	—	36,276	—
Interest rate swaps designated as a hedge	4,684	4,684	—	4,684	—
Interest rate swaps not designated as a hedge	1,383	1,383	—	1,383	—
Commodity contracts for regulated operations	2,928	2,928	—	2,928	—
Total derivative financial instruments	45,271	45,271	—	45,271	—
Total financial liabilities	$1,335,683	$1,427,414	$ 520,142	$ 907,272	$ —

20. 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, 2015 and December 31, 2014 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 liabilities 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 and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace.

The Company’s level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from $20.54 to $109.02 with a weighted average of $38.30 as of September 30, 2015. 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 are detailed in notes 20(b)(ii) and 20(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 fair value recognized on derivative instruments executed with the same counterparty under a master netting arrangement are presented on a gross basis on the consolidated balance sheets. The amounts that could net settle are not significant.

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, 2015 or 2014.

(b) Derivative instruments and hedging relationships

Derivative instruments are recognized on the consolidated balance sheets as either assets or liabilities and measured at fair value 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 service territories. The Company’s strategy is to minimize fluctuations in gas sales prices to regulated customers.

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

	2015
Financial contracts: Gas swaps	1,886,175
Gas options	655,022
	2,541,197

20. Financial instruments (continued)

(b) Derivative instruments and hedging relationships (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 consolidated balance sheets:

	September 30, 2015	December 31, 2014
Regulatory assets:		
Gas swap contracts	U.S. **$ 1,777**	U.S. $ 2,178
Gas option contracts	U.S. **$ 220**	U.S. $ 346

(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 and at one of its hydro facilities no longer subject to a power purchase agreement 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)
60,103	December 2016	$ 68.30	AESO
833,136	December 2022	U.S. $ 42.81	PJM Western HUB
3,564,950	December 2022	U.S. $ 30.25	NI HUB
4,096,939	December 2027	U.S. $ 36.46	ERCOT North HUB

As of September 30, 2015, an amount receivable under the derivatives for Sandy Ridge, Senate and Minonk Wind Facilities of $4,130 (December 31, 2014 - $156) was held as collateral by the counterparty.

On November 14, 2014, the Company entered into a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year $135,000 bond. The change in fair value resulted in a loss of $5,108 and $4,671 for the three and nine months ended September 30, 2015 (2014 - $Nil and $Nil), which is recorded in OCI.

20. Financial instruments (continued)

(b) Derivative instruments and hedging relationships (continued)

(ii) Cash flow hedges (continued)

The following table summarizes changes in OCI attributable to derivative financial instruments designated as a cash flow hedge net of tax:

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	**2015**	2014
Effective portion of cash flow hedge, gain (loss)	**$ 10,516**	$ 8,862	**$ 21,843**	$(18,236)
Amortization on cash flow hedge	**(10)**	(9)	**(27)**	(24)
Gain (loss) reclassified from AOCI into non-regulated energy sales	**(1,178)**	3,621	**(3,083)**	11,648
	$ 9,328	$ 12,474	**$ 18,733**	$ (6,612)
Less non-controlling interest	**—**	—	**—**	5,982
Change in OCI attributable to shareholders of APUC	**$ 9,328**	$ 12,474	**$ 18,733**	$ (630)

The Company expects $12,259 of unrealized gains currently in AOCI to be reclassified into non-regulated energy sales 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 Generation Group's revolving credit facility denominated in U.S. dollars in excess of the principal amount on the USD loan receivable from Odell Wind SponsorCo as a hedge of the foreign currency exposure of its net investment in the Generation Group's U.S. operations. The foreign currency transaction gain or loss on the outstanding U.S. dollar denominated balance of the facility that is designated as a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in OCI) related to the net investment, to the extent it is effective as a hedge. A foreign currency loss of $Nil and $Nil for the three and nine months ended September 30, 2015 (2014- loss of $1,148 and $2,162) was recorded in OCI.

Concurrent with its $150,000 and $200,000 debenture offerings in December 2012 and January 2014, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Generation Group's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A loss of $29,666 and $50,162 (2014 - loss of $15,758 and $12,233) was recorded in OCI for the three months and nine months ended September 30, 2015.

20. Financial instruments (continued)

(b) Derivative instruments and hedging relationships (continued)

(iv) Other derivatives

The Company provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Assets 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.

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, 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 does not currently hedge that risk.

The Company was party to an interest rate swap whereby, the Company paid a fixed interest rate of 4.47% on a notional amount of $58,791 and received floating interest at 90 day CDOR. The swap expired on September 30, 2015. As of September 30, 2015, the estimated fair value of the interest rate swap was $nil (December 31, 2014 – liability of $1,383). This interest rate swap was not accounted for as a hedge.

For derivatives that are not designated as cash flow 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.

The effects on the 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,	
	2015	**2014**	**2015**	**2014**
Change in unrealized loss (gain) on derivative financial instruments:				
Interest rate swaps	**$ (511)**	$ (471)	**$ (1,383)**	$(1,313)
Energy derivative contracts	**138**	(374)	**626**	1,508
Total change in unrealized loss (gain) on derivative financial instruments	**$ (373)**	$ (845)	**$ (757)**	$ 195
Realized loss (gain) on derivative financial instruments:				
Interest rate swaps	**515**	492	**1,498**	1,474
Energy derivative contracts	**42**	178	**(593)**	(3,788)
Total realized loss (gain) on derivative financial instruments	**$ 557**	$ 670	**$ 905**	$(2,314)
Loss (gain) on derivative financial instruments not accounted for as hedges	**184**	(175)	**148**	(2,119)
Ineffective portion of derivative financial instruments accounted for as hedges	**37**	(1,460)	**(2,384)**	1,464
Loss (gain) on derivative financial instruments	**$ 221**	$(1,635)	**$ (2,236)**	$ (655)

21. Comparative figures

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

Notes

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