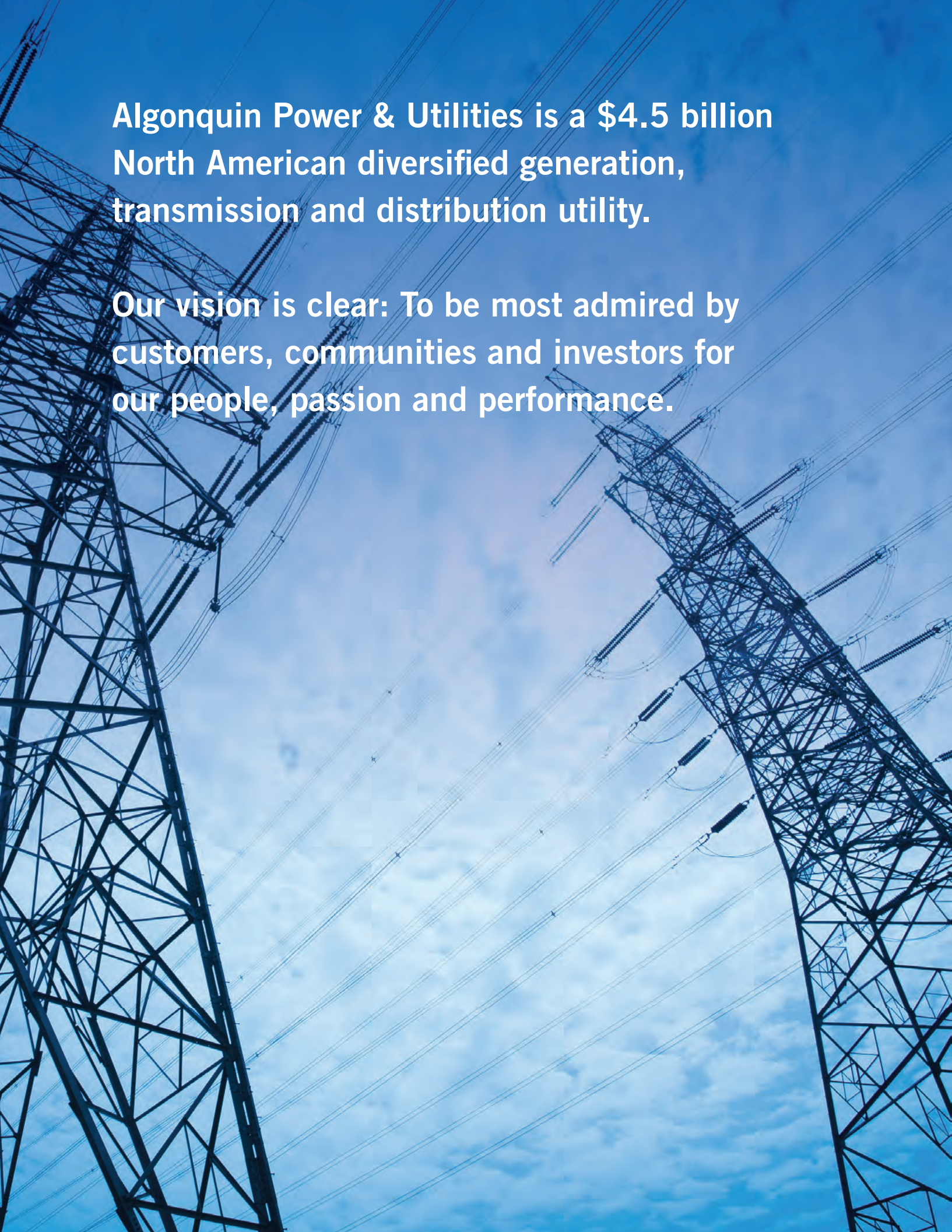




Q2 2015



**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.**

Management Discussion & Analysis

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

Management of Algonquin Power & Utilities Corp. (“APUC” or the “Company”) has prepared the following discussion and analysis to provide information to assist its shareholders’ understanding of the financial results for the three and six months ended June 30, 2015. The Management Discussion & Analysis (“MD&A”) should be read in conjunction with APUC’s unaudited interim consolidated financial statements for the three and six months ended June 30, 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.

This MD&A is based on information available to management as of August 13, 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.

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. \$0.0963 per share or U.S. \$0.3850 per share per annum. Based on exchange rates as at June 30, 2015, the quarterly dividend is equivalent to Cdn \$0.1201 per share or Cdn \$0.4802 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 486 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 489,000 connections. The Distribution Group provides safe, high quality and reliable services to its ratepayers 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 293,000 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

Dividend Increased in Q2 2015 to U.S. \$0.385 (Cdn \$0.48) Per Common Share Annually

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

On May 7, 2015, the Board approved a dividend increase of U.S. \$0.035 annually bringing the total annual dividend to U.S. \$0.385 per common share, paid quarterly at the rate of U.S. \$0.09625 per common share, an increase of 10% over the previous dividend rate. Based on exchange rates as at June 30, 2015, the quarterly dividend is equivalent to Cdn \$0.1201 per share or Cdn \$0.4802 per share per annum.

This most recent dividend increase represents the fifth year in a row that APUC has increased the dividend to common shareholders.

2015 Generation Group Highlights

Completion of Morse Wind Project

On April 22, 2015, the Generation Group completed construction on the 23 MW Morse Wind Project, located near Morse, Saskatchewan. The project is the company's eighth wind generating facility, and consists of 10 2.3 MW direct drive wind turbine generators installed over 1,120 acres of land. The project is expected to generate 104 GW-hrs of energy per year which is being sold under a 20 year power purchase agreement with a large investment grade electric utility.

Completion of Bakersfield I Solar Project

On April 14, 2015, the Generation Group achieved COD in accordance with the provisions of the PPA at its 20 MW Bakersfield I Solar Project, located in Kern County, California. The project is the Generation Group's second solar generating facility and is comprised of approximately 85,000 solar panels located on 165 acres of land. The project is expected to generate 53.3 GW-hrs of energy per year which is being sold under a 20 year power purchase agreement with a large investment grade electric utility.

Consistent with the commitment to expand its solar generation portfolio, the Generation Group is currently pursuing the construction of the 10 MW Bakersfield II Solar Project immediately adjacent to the Bakersfield I Solar Facility, which is estimated to be operational in the first half of 2016.

DBRS Rating Trend Changed to Positive

Subsequent to quarter end DBRS announced that they have reaffirmed the Generation Group's Issuer Rating and Senior Unsecured Debentures of BBB low and changed the trend to Positive. DBRS noted that the Positive trend reflects their view that the Generation Group's credit metrics strengthened and moved solidly into the mid-BBB range. The Generation Group views the trend change as credit positive and beneficial to its cost of capital.

2015 Distribution Group Highlights

Successful Rate Case Outcomes

A core strategy of the Distribution Group is to ensure appropriate return on the rate base at its various utility systems. During the second quarter of 2015, the Distribution Group obtained a final order on the EnergyNorth rate case approving a U.S. \$12.4 million revenue increase effective July 1, 2015. Further details on these and other regulatory proceedings of the Distribution Group can be found later in this MD&A under Regulatory Proceedings.

U.S. Debt Private Placement

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 notes were issued in two tranches: U.S. \$90 million was issued immediately on closing and U.S. \$70 million was issued subsequent to the quarter end 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.

2015 Transmission Group Highlights

Northeast Energy Direct Pipeline

During the quarter, Kinder Morgan, Inc. announced that its board of directors has authorized proceeding with its Northeast Energy Direct (NED) project between Wright, New York and Dracut, Massachusetts. This is a \$3.3 billion investment designed to serve natural gas utilities and electricity generation customers in New England. The pipeline is currently sized as a 30 inch in diameter, 1.3 Bcf/d pipeline to serve the commitments received from New England local gas distribution companies.

While NED is currently designed as a 30-inch pipeline, as more capacity commitments are made a modification to a 36-inch pipeline design could still be made which would require an amended filing to be made with the FERC. Subject to the receipt of regulatory permits, NED is anticipated to commence service in November 2018.

The Transmission Group holds a 2.5% investment in the project with an option to invest up to 10%.

2015 Second Quarter Results From Operations

Key Selected Second Quarter Financial Information

(all dollar amounts in \$ millions except per share information)	Three months ended June 30,	
	2015	2014
Revenue	\$ 196.2	\$ 188.6
Adjusted EBITDA ¹	81.1	66.4
Cash provided by operating activities	98.8	84.5
Adjusted funds from operations ¹	55.2	39.1
Net earnings attributable to shareholders from continuing operations	20.6	15.2
Net earnings attributable to shareholders	19.9	14.6
Adjusted net earnings ¹	22.2	16.6
Dividends declared to common shareholders	30.3	17.3
Weighted Average number of common shares outstanding ³	251,440,347	207,354,112
Per share		
Basic net earnings from continuing operations	\$ 0.07	\$ 0.06
Basic net earnings	\$ 0.07	\$ 0.06
Adjusted net earnings ^{1, 2}	\$ 0.08	\$ 0.07
Diluted net earnings	\$ 0.07	\$ 0.06
Cash provided by operating activities ^{1, 2}	\$ 0.39	\$ 0.41
Adjusted funds from operations ^{1, 2}	\$ 0.22	\$ 0.17
Dividends declared to common shareholders	\$ 0.12	\$ 0.09

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 June 30, 2015, APUC experienced an average U.S. exchange rate of approximately \$1.2291 as compared to \$1.0970 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 June 30, 2015, APUC reported total revenue of \$196.2 million as compared to \$188.6 million during the same period in 2014, an increase of \$7.6 million. The major factors resulting in the increase in APUC revenue in the three months ended June 30, 2015 as compared to the corresponding period in 2014 are set out as follows:

(all dollar amounts in \$ millions)

Three months ended
June 30, 2015

Comparative Prior Period Revenue	\$	188.6
Significant Changes:		
Decreased wind resources at all facilities partially offset by favorable settlements on periodic production shortfalls under power hedges at the Minonk, Senate and Sandy Ridge Wind Facilities along with higher pricing realized on sale of the unhedged portion of energy produced.		(2.2)
Start of commercial operations of the St. Damase (Q4'14) and Morse (Q2'15) Wind Facilities.		3.7
Start of commercial operations at the Bakersfield I Solar Facility (Q2'15).		1.0
Decreased hydrological resources in the Quebec and Western regions, in addition to decreased customer load and retail pricing in the Maritime region; partially offset by increased production in the Ontario region.		(2.3)
Lower production and cost of gas (which is a direct pass-through to customers) at the Windsor Locks and Sanger Thermal Facilities.		(1.5)
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, partially offset by higher demand at the New England Gas Systems.		(18.5)
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.		6.7
Increase in revenue due to the acquisitions of the White Hall Water & Waste System (Q2'14) and the New Hampshire Gas System (Q1'15).		1.1
Increased demand for natural gas transportation.		1.5
Impact of the stronger U.S. dollar.		18.2
Other		(0.1)
Current Period Revenue	\$	196.2

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

Adjusted EBITDA in the three months ended June 30, 2015 totalled \$81.1 million as compared to \$66.4 million during the same period in 2014, an increase of \$14.7 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 June 30, 2015, net earnings attributable to Shareholders from continued operations totalled \$20.6 million as compared to \$15.2 million during the same period in 2014, an increase of \$5.4 million. The increase was due to \$15.2 million in increased earnings from operating facilities, \$0.9 million in increased foreign currency gains, \$1.3 million increase in other gains, \$3.7 million in increased gains from derivative instruments, and \$0.3 million in reduced allocation of earnings to non-controlling interests, as compared to the same period in 2014. These items were partially offset by \$10.6 million in increased depreciation and amortization expenses, \$0.3 million in increased administration charges, \$0.4 million in increased interest expense, \$0.8 million in decreased interest and dividend income, \$0.2 million in increased acquisition costs and \$3.7 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*).

For the three months ended June 30, 2015, net earnings (including discontinued operations) attributable to Shareholders totalled \$19.9 million as compared to net earnings attributable to Shareholders of \$14.6 million during the same period in 2014, an increase of \$5.3 million. Net earnings per share totalled \$0.07 for the three months ended June 30, 2015, as compared to net earnings per share of \$0.06 during the same period in 2014.

During the three months ended June 30, 2015, cash provided by operating activities totalled \$98.8 million or \$0.39 per share as compared to cash provided by operating activities of \$84.5 million, or \$0.41 per share during the same period in 2014. During the three months ended June 30, 2015, adjusted funds from operations totalled \$55.2 million or \$0.22 per share as compared to adjusted funds from operations of \$39.1 million, or \$0.17 per share during the same period in 2014. The change in adjusted funds from operations in the three months ended June 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 Six Month Results From Operations

Key Selected Six Months Financial Information

(all dollar amounts in \$ millions except per share information)	Six months ended June 30,	
	2015	2014
Revenue	\$ 578.0	\$ 530.7
Adjusted EBITDA ¹	195.6	164.8
Cash provided by operating activities	91.4	99.4
Adjusted funds from operations ¹	156.1	121.9
Net earnings attributable to shareholders from continuing operations	63.7	50.9
Net earnings attributable to shareholders	63.0	50.5
Adjusted net earnings ¹	64.6	53.6
Dividends declared to common shareholders	58.2	35.2
Weighted Average number of common shares outstanding ⁴	251,110,176	207,067,645
Per share		
Basic net earnings from continuing operations	\$ 0.23	\$ 0.22
Basic net earnings	\$ 0.23	\$ 0.22
Adjusted net earnings ^{1, 2}	\$ 0.25	\$ 0.24
Diluted net earnings	\$ 0.23	\$ 0.22
Cash provided by operating activities ^{1, 2}	\$ 0.36	\$ 0.48
Adjusted funds from operations ^{1, 2}	\$ 0.63	\$ 0.57
Dividends declared to common shareholders	\$ 0.23	\$ 0.17
Total assets	4,396.5	4,105.1
Long term liabilities ³	1,440.3	1,381.0

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 six months ended June 30, 2015, APUC experienced an average U.S. exchange rate of approximately \$1.2351 as compared to \$1.0970 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 six months ended June 30, 2015, APUC reported total revenue of \$578.0 million as compared to \$530.7 million during the same period in 2014, an increase of \$47.3 million or 9%. The major factors resulting in the increase in APUC revenue for the six months ended June 30, 2015, as compared to the corresponding period in 2014 are set out as follows:

(all dollar amounts in \$ millions)

Comparative Prior Period Revenue	\$	530.7
Significant Changes:		
Decreased wind resources at all facilities other than Sandy Ridge partially offset by favorable settlements on periodic production shortfalls under power hedges at the Minonk, Senate and Sandy Ridge Wind Facilities along with higher pricing realized on sale of the unhedged portion of energy produced.		(1.3)
Start of commercial operations of the St. Damase (Q4'14) and Morse (Q2'15) Wind Facilities.		5.8
Start of commercial operations at the Cornwall (Q1'14) and Bakersfield I (Q2'15) Solar Facilities.		2.1
Decreased hydrological resources in the Quebec and Western regions; decreased customer load and retail pricing in the Maritime region; partially offset by increased production in the Ontario region.		(5.4)
Higher realized prices from Renewable Energy Credits partially offset by lower production from the U.S. Wind facilities.		1.2
Lower production and cost of gas (which is a direct pass-through to customers) at the Windsor Locks and Sanger Thermal Facilities.		(5.7)
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 System, partially offset by higher demand at the New England Gas Systems.		(26.1)
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.		12.1
Increase in revenue due to the acquisitions of the White Hall Water & Waste System (Q2'14) and the New Hampshire Gas System (Q1'15).		3.5
Increased demand for natural gas transportation.		3.1
Increased revenues at Peach State Gas System's Fort Benning operations.		1.6
Impact of the stronger U.S. dollar.		57.5
Other		(1.1)
Current Period Revenue	\$	578.0

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

Adjusted EBITDA in the six months ended June 30, 2015 totalled \$195.6 million as compared to \$164.8 million during the same period in 2014, an increase of \$30.8 million. The increase in Adjusted EBITDA was primarily due to impact of rate case settlements, full six 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 six months ended June 30, 2015, net earnings from continuing operations attributable to Shareholders totalled \$63.7 million as compared to \$50.9 million during the same period in 2014, an increase of \$12.8 million. The increase was due to \$36.8 million in increased earnings from operating facilities, \$0.4 million in increased foreign currency gains, \$2.4 million increase in other gains, \$0.4 million in decreased property plant and equipment write-downs, \$3.4 million in increased gain from derivative instruments, and \$4.0 million in reduced allocations of earnings to non-controlling interests as compared to the same period in 2014. These items were partially offset by \$18.7 million in increased depreciation and amortization expenses, \$3.0 million in increased administration charges, \$0.8 million in increased interest expense, \$0.6 million in decreased interest and other income, \$0.3 million increase in acquisition costs, and \$11.2 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 six months ended June 30, 2015, net earnings (including discontinued operations) attributable to Shareholders totalled \$63.0 million as compared to \$50.5 million during the same period in 2014, an increase of \$12.5 million. Net earnings per share totalled \$0.23 for the six months ended June 30, 2015, as compared to \$0.22 during the same period in 2014.

During the six months ended June 30, 2015, cash used by operating activities totalled \$91.4 million or \$0.36 per share as compared to cash provided by operating activities of \$99.4 million, or \$0.48 per share during the same period in 2014. During the six months ended June 30, 2015, adjusted funds from operations, a non-GAAP measure, totalled \$156.1 million

or \$0.63 per share as compared to adjusted funds from operations of \$121.9 million, or \$0.57 per share during the same period in 2014, an increase of \$34.2 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 June 30,		Long Term Average Resource	Six months ended June 30,	
		2015	2014		2015	2014
Performance (GW-hrs sold)						
Hydro Facilities:						
Maritime Region	72.2	53.6	53.7	107.9	80.9	87.4
Quebec Region ¹	82.4	77.8	81.0	139.5	126.5	129.6
Ontario Region	37.2	38.1	34.7	75.5	75.9	72.2
Western Region	19.0	11.7	21.4	28.6	22.9	33.8
	210.8	181.2	190.8	351.5	306.2	323.0
Wind Facilities:						
Morse ²	20.8	19.1	—	20.8	19.1	—
Red Lily ³	20.8	18.3	20.4	44.0	40.7	47.9
St. Damase ⁴	18.5	16.0	—	39.4	36.5	—
St. Leon	99.5	93.8	106.0	220.9	217.7	238.9
Sandy Ridge	37.7	36.2	35.1	84.8	86.0	79.8
Minonk	170.3	156.3	164.7	370.9	333.0	364.0
Senate	137.4	119.9	158.1	288.7	229.2	305.8
Shady Oaks	101.4	76.5	88.8	211.1	176.5	201.5
	606.4	536.1	573.1	1,280.6	1,138.7	1,237.9
Solar Facilities:						
Cornwall	4.9	5.5	5.2	8.1	7.8	5.3
Bakersfield I ⁵	18.0	16.3	—	18.0	17.9	—
	22.9	21.8	5.2	26.1	25.7	5.3
Total Performance	840.1	739.1	769.1	1,658.2	1,470.6	1,566.2

¹ The Generation Group's Donnacona Hydro Facility was offline during the first and second quarters of 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 June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Revenue¹				
Hydro	\$ 13.9	\$ 15.8	\$ 29.7	\$ 34.4
Wind	26.5	23.3	56.8	48.2
Solar	3.6	2.3	4.7	2.4
Total Revenue	\$ 44.0	\$ 41.4	\$ 91.2	\$ 85.0
Less:				
Cost of Sales - Energy ²	(0.8)	(2.0)	(7.1)	(12.4)
Realized gain on hedges ³	—	—	0.6	4.0
Net Energy Sales	\$ 43.2	\$ 39.4	\$ 84.7	\$ 76.6
Renewable Energy Credits ("REC") ⁴	4.3	4.2	8.9	6.5
Other Revenue	0.3	0.2	0.7	0.9
Total Net Revenue	\$ 47.8	\$ 43.8	\$ 94.3	\$ 84.0
Expenses & Other Income				
Operating expenses	(13.3)	(11.8)	(25.9)	(23.0)
Interest and Other income	—	0.4	0.9	0.8
HLBV income	8.0	7.5	16.9	16.0
Divisional operating profit	\$ 42.5	\$ 39.9	\$ 86.2	\$ 77.8

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 Renewable Energy Credits (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 Second Quarter Operating Results

For the three months ended June 30, 2015, the hydro facilities generated 181.2 GW-hrs of electricity, as compared to 190.8 GW-hrs produced in the same period in 2014, a decrease of 5%. The decreased generation is largely attributable to significantly reduced flows in the Western Region, the Donnacona Hydro Facility being offline throughout the quarter and lower hydrology resources caused by a shorter spring runoff in the Maritime region.

During the three months ended June 30, 2015, the hydro facilities generated electricity equal to 86.0% of long-term average resource ("LTAR") as compared to 91% during the same period in 2014. During the three months ended June 30, 2015, the Ontario region achieved production greater than its long-term average. The Quebec region was below the long term average due to Donnacona being offline. Excluding Donnacona, the Quebec region achieved 104% of the long-term average resources. The Maritime region was below its LTAR due to a shorter than usual spring freshet. The Western region was below its long-term average resources due to flow restrictions imposed by Alberta Energy at Dickson Dam related to low water levels in the area.

For the three months ended June 30, 2015, revenue from the hydro facilities totalled \$13.9 million as compared to \$15.8 million during the same period in 2014, a decrease of \$1.9 million. Lower revenues were recorded in the Quebec, Maritime and Western regions due to a combination of lower production, lower prices for power and reduced customer loads. This was offset by higher revenue in the Ontario region due to better hydrology and increased pricing.

For the three months ended June 30, 2015, energy purchase costs at the Maritime region totalled \$0.8 million, as compared to \$2.0 million during the same period in 2014, a decrease of \$1.2 million. The decrease in the energy purchase costs for the three months ended June 30, 2015 were primarily due to decreased retail customer load served requiring reduced energy purchases from the market.

During the three months ended June 30, 2015, the Maritime region generated approximately 53% of the load required to service its customers, as compared to 41% 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 June 30, 2015, the wind facilities produced 536.1 GW-hrs of electricity, as compared to 573.1 GW-hrs produced in the same period in 2014, a decrease of 6.5%. The decreased generation was a result of reduced wind resources at most sites partially offset by production from the newly operational St. Damase and Morse Wind Facilities.

During the three months ended June 30, 2015, the wind facilities (excluding the St. Damase and Morse Wind Facilities) generated electricity equal to 88.3% of long-term projected average resources, as compared to 101.1% during the same period in 2014, due to the lower wind resource in the quarter.

For the three months ended June 30, 2015, revenue from the wind facilities totalled \$26.5 million as compared to \$23.3 million during the same period in 2014, an increase of \$3.2 million. The increase in revenue was primarily attributable to the Morse and St. Damase Wind Facilities reaching COD in Q2 2015 and Q4 2014 respectively, and a higher average U.S. dollar exchange rate. The increase in revenue was partially offset by reduced wind resources.

For the three months ended June 30, 2015, REC revenue totalled \$4.3 million, as compared to \$4.2 million in the same period in 2014, an increase of \$0.1 million. The increase in REC revenue was a result of increased pricing in the PJM region and a stronger U.S. dollar, partially offset by decreased energy production from the US wind facilities which resulted in fewer RECs available to be sold in the market. The increase in market pricing is largely caused by the annually increasing renewable requirement of the Renewable Portfolio Standard outpacing the increase in supply of available RECs. 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 June 30, 2015, REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities.

During the three months ended June 30, 2015, the Generation Group's solar facilities generated 21.8 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 COD in accordance with the provisions of the PPA on April 14, 2015.

Cornwall's production was equal to 112.2% of its long-term average resources, as compared to 106.1% in the same period last year.

Revenue from generation at the Generation Group's solar facilities totalled \$3.6 million for the period as compared to \$2.3 million in the same period of 2014 due to the increased quantity of power generated.

For the three months ended June 30, 2015, operating expenses excluding energy purchases totalled \$13.3 million, as compared to \$11.8 million during the same period in 2014, an increase of \$1.5 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 18.3 GW-hrs of electricity for the three months ended June 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 June 30, 2015, the Generation Group earned fees of \$0.3 million which is classified as other revenue.

For the three months ended June 30, 2015, interest and other income totalled nil as compared to \$0.4 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 June 30, 2015, the value of net tax attributes generated HLBV income of \$8.0 million, as compared to \$7.5 million during the same period in 2014, an increase of \$0.5 million compared to the prior period. The increase is primarily a result of \$0.8 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 PTCs as compared to the prior year.

For the three months ended June 30, 2015, the Renewable Energy Division's operating profit totalled \$42.5 million, as compared to \$39.9 million during the same period in 2014, an increase of \$2.6 million; 3.0 million of the increase in attributable to the stronger U.S. dollar.

2015 Six Month Operating Results

For the six months ended June 30, 2015, the hydro facilities generated 306.2 GW-hrs of electricity, as compared to 323.0 GW-hrs produced in the same period in 2014, a decrease of 5%. The decrease in generation is due to lower hydrology combined with the Donnacona Hydro Facility in Quebec being offline and lower production in the Western Region due to water flow restrictions.

During the six months ended June 30, 2015, the hydro facilities generated electricity equal to 87.1% of long-term projected average resources, as compared to 92% during the same period in 2014. During the six months ended June 30, 2015, the Ontario region achieved production above its long-term average while the Quebec, Western and Maritime region produced below their long term average. The Quebec region achieved 91% 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 97% of its long term average.

For the six months ended June 30, 2015, revenue from the hydro facilities totalled \$29.7 million, as compared to \$34.4 million during the same period in 2014, a decrease of \$4.7 million. Revenue from generation in the Ontario region increased by \$1.0 million due to improved production at the Long Sault Hydro Facility, while the Western region experienced a decrease of \$0.9 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 Donnacona being offline have been made up by business interruption insurance proceeds. Revenue from the Maritime region decreased \$4.3 million, primarily due to decreased retail customer load served.

For the six months ended June 30, 2015, energy purchases related to the Maritime region totalled \$7.1 million, as compared to \$12.4 million during the same period in 2014, a decrease of \$5.3 million. The decrease in energy purchases for the six months ended June 30, 2015 was a result of the lower retail customer load which decreased the overall energy purchase requirement. In addition, the average energy purchase price was significantly lower than the abnormally high prices of the first quarter of 2014.

During the six months ended June 30, 2015, the Maritime region generated approximately 39% of the load required to service its customers, as compared to 34% 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 six months ended June 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 \$3.4 million for six months ended June 30, 2015 as compared to \$3.7 million in the same quarter in the prior year a decrease of \$0.3 million.

For the six months ended June 30, 2015, the wind facilities produced 1,138.7 GW-hrs of electricity, as compared to 1,237.9 GW-hrs produced in the same period in 2014, a decrease of 8%. The decreased generation was a result of weaker wind resources at all facilities except the Sandy Ridge Wind Facility partially offset by production at the new Morse and St. Damase Wind Facilities.

During the six months ended June 30, 2015, the wind facilities generated electricity equal to 89% of long-term average resources, as compared to 101% during the same period in 2014. For the six months ended June 30, 2015, revenue from the wind facilities totalled \$56.8 million, as compared to \$48.2 million during the same period in 2014, an increase of \$8.6 million. Revenue from the Generation Group's Canadian wind facilities increased \$4.3 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 \$4.0 million primarily as a result of realizing higher net revenues from the hedges on certain U.S. wind facilities along with 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 of the facilities other than the Sandy Ridge Wind Facility.

For the six months ended June 30, 2015, REC revenue totalled \$8.9 million, as compared to \$6.5 million in the same period in 2014, an increase of \$2.4 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. 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.

During the six months ended June 30, 2015, the Generation Group's solar facilities generated 25.7 GW-hrs of electricity, as compared to 5.3 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 96% of its long-term average resources, as compared to 106.1% in the same period last year.

Revenue from generation at the Generation Group's solar facilities totalled \$4.7 million for the period as compared to \$2.4 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 six months ended June 30, 2015, operating expenses excluding energy purchases totalled \$25.9 million, as compared to \$23.0 million during the same period in 2014, an increase of \$2.9 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.

For the six months ended June 30, 2015, interest and other income totalled \$0.9 million, as compared to \$0.8 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.

The Red Lily I Wind Facility located in Saskatchewan produced 40.7 GW-hrs of electricity for the six months ended June 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 six months ended June 30, 2015, the Generation Group earned fees of \$0.7 million (which is classified as other revenue) and interest income of \$0.9 million from the Red Lily I Wind Facility.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of net tax attributes, primarily related to electricity production generated by the Generation Group in the period from certain of its U.S. wind and solar power generation facilities. The value of net tax attributes generated in the six months ended June 30, 2015 amounted to HLBV income of \$16.9 million, as compared to \$16.0 million in the prior year. The increase is primarily a result of \$1.9 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 PTCs as compared to the prior year.

For the six months ended June 30, 2015, the Renewable Energy Division's operating profit totalled \$86.2 million, as compared to \$77.8 million during the same period in 2014, an increase of \$8.4 million; \$6.0 million of the increase is attributable to the stronger U.S. dollar.

Generation Business Group

Thermal Energy Division

	Three months ended June 30, 2015			Three months ended June 30, 2014		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance (GW-hrs sold)	29.5	28.9	58.4	25.1	30.3	55.4
Performance (steam sales – billion lbs)	140.5	—	140.5	138.7	—	138.7
(all dollar amounts in \$ millions)						
Revenue						
Energy/steam sales	\$ 3.8	\$ 4.6	\$ 8.4	\$ 4.0	\$ 5.1	\$ 9.1
Less:						
Cost of Sales – Fuel	(1.9)	(1.2)	(3.1)	(2.1)	(1.7)	(3.8)
Net Energy/Steam Sales	\$ 1.9	\$ 3.4	\$ 5.3	\$ 1.9	\$ 3.4	\$ 5.3
Other Revenue	0.7	0.5	1.2	0.3	0.5	0.8
Total Net Revenue	\$ 2.6	\$ 3.9	\$ 6.5	\$ 2.2	\$ 3.9	\$ 6.1
Expenses						
Operating Expenses	(1.9)	(1.2)	(3.1)	(1.5)	(1.4)	(2.9)
Facility operating profit	\$ 0.7	\$ 2.7	\$ 3.4	\$ 0.7	\$ 2.5	\$ 3.2
Interest and other income			—			0.2
Divisional operating profit			\$ 3.4			\$ 3.4

2015 Second 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 June 30, 2015, the Thermal Energy Division's operating profit was consistent with the previous year coming in at \$3.4 million. Operating profit contributions for the three months ended June 30, 2015 were \$0.7 million from the Windsor Locks Thermal Facility and \$2.7 million from the Sanger Thermal Facility, as compared to \$0.7 million and \$2.5 million, respectively, during the same period in 2014. Interest and other income for the three months ended June 30, 2015 was nil, as compared to income of \$0.2 million in the prior period. As a result of the stronger U.S. dollar, operating profit increased by \$0.4 million.

Windsor Locks Thermal Facility

For the three months ended June 30, 2015, the Windsor Locks Thermal Facility sold 29.5 GW-hrs of electricity and 140.5 billion lbs of steam, as compared to 25.1 GW-hrs of electricity and 138.7 billion lbs of steam in the comparable period of 2014.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of \$3.8 million (U.S. \$3.1 million), as compared to \$4.0 million (U.S. \$3.6 million) in the same period in 2014. The change in electricity/steam sales is attributed to higher production offset by a lower average price for gas. Gas costs for the period were \$1.9 million (U.S. \$1.6 million), as compared to \$2.1 million (U.S. \$1.9 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 June 30, 2015, net sales at the Windsor Locks Thermal Facility totalled \$1.9 million (U.S. \$1.5 million) which was consistent with the same period in 2014.

Operating expenses excluding fuel costs were \$1.9 million (U.S. \$1.5 million), as compared to \$1.5 million (U.S. \$1.4 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 June 30, 2015 was \$0.7 million which was consistent with the prior period.

Sanger Thermal Facility

For the three months ended June 30, 2015, the Sanger Thermal Facility sold 28.9 GW-hrs of electricity, as compared to 30.3 GW-hrs of electricity in the comparable period of 2014.

For the three months ended June 30, 2015, the Sanger Thermal Facility's operating profit was driven by energy/steam sales of \$4.6 million (U.S. \$3.6 million), as compared to \$5.1 million (U.S. \$4.7 million) in the same period in 2014, a decrease of \$0.5 million. The decrease in energy/steam sales is primarily due to lower gas prices which are passed on to customers, as compared to the same period in 2014. Capacity revenues increased to \$3.0 million as compared to \$2.7 million in the same period in 2014, entirely due to the stronger U.S. exchange rate. Gas costs for the period were \$1.2 million (U.S. \$1.0 million), as compared to \$1.7 million (U.S. \$1.5 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 June 30, 2015, net energy sales at the Sanger Thermal Facility totalled \$3.4 million (U.S. \$2.6 million), as compared to \$3.4 million (U.S. \$3.1 million) during the same period in 2014.

Operating expenses excluding natural gas costs were \$1.2 million (U.S. \$1.0 million), as compared to \$1.4 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 June 30, 2015 was \$2.7 million, as compared to \$2.5 million during the same period in 2014.

Thermal Energy Division

	Six months ended June 30, 2015			Six months ended June 30, 2014		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance (GW-hrs sold)	57.5	60.8	118.3	57.8	62.3	120.1
Performance (steam sales – billion lbs)	336.9	—	336.9	339.9	—	339.9
(all dollar amounts in \$ millions)						
Revenue						
Energy/steam sales	\$ 11.5	\$ 7.4	\$ 18.9	\$ 14.9	\$ 8.5	\$ 23.4
Less:						
Cost of Sales – Fuel	(7.6)	(2.7)	(10.3)	(10.1)	(3.6)	(13.7)
Net Energy/Steam Sales	\$ 3.9	\$ 4.7	\$ 8.6	\$ 4.8	\$ 4.9	\$ 9.7
Other revenue	1.0	1.1	2.1	0.9	0.7	1.6
Total net revenue	\$ 4.9	\$ 5.8	\$ 10.7	\$ 5.7	\$ 5.6	\$ 11.3
Expenses						
Operating expenses	(3.1)	(2.6)	(5.7)	(2.8)	(2.4)	(5.2)
Facility operating profit	\$ 1.8	\$ 3.2	\$ 5.0	\$ 2.9	\$ 3.2	\$ 6.1
Interest and other income			\$ 0.1			\$ —
Divisional operating profit			5.1			6.1

2015 Six 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 six months ended June 30, 2015, the Thermal Energy Division's operating profit was \$5.1 million, as compared to \$6.1 million in the same period in 2014, a decrease of \$1.0 million. The Windsor Locks Thermal Facility contributed \$1.8 million, while the Sanger Thermal Facility contributed \$3.2 million of operating profit during the six months ended June 30, 2015, as compared to \$2.9 million and \$3.2 million, respectively, during the same period in the prior year. Interest and other income for the six months ended June 30, 2015 was \$0.1 million as compared to nil, during the same period in the prior year.

Windsor Locks Thermal Facility

For the six months ended June 30, 2015, the Windsor Locks Thermal Facility sold 57.5 GW-hrs of energy and 336.9 billion lbs of steam, as compared to 57.8 GW-hrs of energy and 339.9 billion lbs of steam in the comparable period of 2014.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of \$11.5 million (U.S. \$9.3 million), as compared to \$14.9 million (U.S. \$13.6 million) in the same period, a decrease of \$3.4 million. The decrease in energy/steam sales is primarily attributed to lower volume and lower prices realized in the merchant market earlier in the year. Gas costs for the period were \$7.6 million (U.S. \$6.1 million) as compared to \$10.1 million (U.S. \$9.2 million) in the same period in 2014, a decrease of \$2.5 million. The decrease in gas costs is a result of the decrease in the average landed cost of natural gas per MMBTU in the first quarter of 2015 in addition to lower volumes purchased due to decreased demand, as compared to the same period in 2014 which experienced below seasonal temperatures during the first quarter.

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 six months ended June 30, 2015, net energy/steam sales at the Windsor Locks Thermal Facility totalled \$3.9 million, as compared to \$4.8 million during the same period in 2014, a decrease of \$0.9 million 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 \$3.1 million (U.S. \$2.5 million), as compared to \$2.8 million (U.S. \$2.6 million) during the same period in 2014, an increase of \$0.3 million primarily due to a stronger U.S. dollar exchange rate. The main items in operating expense for the period were repairs and maintenance expense and cost of RECs sold from inventory (an offset to operating expense is booked when a REC is generated and is recorded as inventory and reversed when sold) partly offset by a stronger U.S. dollar. The Windsor Locks Thermal Facility's resulting net operating income for the six months ended June 30, 2015 was \$1.8 million, as compared to \$2.9 million in the same period in 2014, a decrease of \$1.1 million.

Sanger Thermal Facility

For the six months ended June 30, 2015, the Sanger Thermal Facility sold 60.8 GW-hrs of energy, as compared to 62.3 GW-hrs of energy in the comparable period of 2014.

For the six months ended June 30, 2015, the Sanger Thermal Facility's operating profit was driven by energy/steam sales of \$7.4 million (U.S. \$6.0 million), as compared to \$8.5 million (U.S. \$7.7 million) in the same period in 2014, a decrease of \$1.1 million. The decrease in energy/steam sales is primarily attributable to decreased gas prices, which is a pass through to customers, as well as fewer hours run to capture an increase in the contract basis differential in comparison to 2014. Capacity revenue remained unchanged at \$3.4 million. Gas costs for the period were \$2.7 million (U.S. \$2.2 million) as compared to \$3.6 million (U.S. \$3.2 million) in the same period in 2014, a decrease of \$0.9 million. The decrease in gas costs is largely due to a 31.3% 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 six months ended June 30, 2015, net energy sales at the Sanger Thermal Facility totalled \$4.7 million (U.S. \$3.6 million), as compared to \$4.9 million (U.S. \$4.6 million) during the same period in 2014, a decrease of \$0.2 million, caused primarily by the decrease in gas prices and lower off peak generation during the quarter, as discussed above.

Operating expenses excluding natural gas costs were \$2.6 million (U.S. \$2.0 million), as compared to \$2.4 million (U.S. \$2.2 million) during the same period in 2014. The Sanger Thermal Facility's resulting net operating income for the six months ended June 30, 2015 was \$3.2 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	\$ 403.2	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	\$ 33.7	2016	20	24.2
Total Projects in Construction		234	\$ 506.9			904.9
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		486	\$ 1,119.4			1,859.9

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.

Projects in Construction

Odell Wind Project

The 200MW Odell Wind Project is located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota.

A Limited Notice to Proceed was issued early in the second quarter and construction commenced in mid-May 2015. The EPC Contractor has completed the majority of the access roads and has started work on the turbine foundations and the collector system. Work on the two substations is underway, and approximately 75% of the transmission line poles have been installed.

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.

Commission de Protection du Territoire Agricole Quebec ("CPTAQ") approval and Certificate of Authorization have been received for ten turbine locations, roads, and the collection system. Land agreements have all been secured. Substation equipment has been ordered and the BOP Agreements are under negotiations. The Enercon turbine supply contract signing and balance of plant construction will occur once the construction schedule is finalized in conjunction with community partner.

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 first quarter the conditional use permit and the material modification application permitting compliance binders were submitted to the County. The Generation Group has begun procurement of long lead electrical equipment, and the engineering and design of the facility are underway.

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”) application was submitted in April 2013 and posted to the environmental registry in early January 2014 and continues to undergo technical review. The previously disclosed project changes to optimize construction and project performance, which involved reducing the number of turbines from 33 to 26 and rerouting the collection system to avoid the village of Stella were implemented with a posting on the project website in May 2015.

Once the REA is issued, it may be appealed by interested parties within 15 days of its release. If the REA is appealed, the appeal process is expected to take up to 6 months. Other permitting processes, and the engineering and procurement of long-lead equipment are progressing according to schedule. 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 has conducted an RFP for dock construction on the mainland and island which will be the first construction activity undertaken and procured the submarine cable which is a key portion of the interconnection infrastructure that will be installed linking the island to the mainland.

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. A supplemental report was submitted in the second quarter of 2015. The turbine selection will be finalized upon signing of the Turbine Supply Agreement, which is expected to take place in the third quarter.

Distribution Business Group

The Distribution Group operates rate-regulated utilities providing distribution services to approximately 489,000 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 (all dollar amounts in U.S. \$ millions)	June 30, 2015		June 30, 2014	
	Assets	Connections	Assets	Connections
Electricity	\$ 330.6	93,000	\$ 289.8	92,000
Natural Gas	748.6	293,000	679.6	291,000
Water and Wastewater	260.2	103,000	239.3	102,000
Total	\$ 1,339.4	489,000	\$ 1,208.7	485,000
Accumulated Deferred Income Taxes	\$ 92.5		\$ 92.7	

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 293,000 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 June 30,		Three months ended June 30,	
	2015 U.S. \$ (millions)	2014 U.S. \$ (millions)	2015 Can \$ (millions)	2014 Can \$ (millions)
Revenue				
Utility electricity sales and distribution	\$ 37.9	\$ 40.8	\$ 46.6	\$ 44.5
Less: Cost of Sales – Electricity	(20.5)	(22.7)	(25.2)	(24.7)
Net Utility Sales - Electricity	\$ 17.4	\$ 18.1	\$ 21.4	\$ 19.8
Utility natural gas sales and distribution	51.1	60.1	62.8	65.7
Less: Cost of Sales – Natural Gas	(16.4)	(30.2)	(20.3)	(33.0)
Net Utility Sales - Natural Gas	\$ 34.7	\$ 29.9	\$ 42.5	\$ 32.7
Net Utility Sales - Water Distribution & Wastewater Treatment	15.6	15.1	19.2	16.4
Gas Transportation	6.7	5.2	8.2	5.6
Other Revenue	1.0	0.7	1.2	0.8
Net Utility Sales	\$ 75.4	\$ 69.0	\$ 92.5	\$ 75.3
Operating expenses	(40.8)	(41.9)	(50.2)	(45.5)
Other income	0.8	0.8	1.0	1.0
Distribution Group operating profit	\$ 35.4	\$ 27.9	\$ 43.3	\$ 30.8

2015 Second Quarter Operating Results

For the three months ended June 30, 2015, the Distribution Group reported an operating profit of U.S. \$35.4 million, as compared to U.S. \$27.9 million for the comparable period in the prior year. The increase is primarily due to the implementation of interim rates at the EnergyNorth Gas System, the recognition of additional revenue related to the implementation of the final rate case at the EnergyNorth Gas System representing the difference between interim rates granted and final rates retroactive to November 1, 2014, and the implementation of final rates as a result of the general rate case at the Missouri and Illinois Gas Systems. Detailed results are discussed in the following sections. Measured in Canadian dollars, the group's operating profit was \$43.3 million, as compared to \$30.8 million for the comparable period in the prior year. In addition to the factors described below, operating profit measured in Canadian dollars increased by \$5.0 million due to a stronger U.S. dollar.

Electric Distribution Systems

	Three months ended June 30	
	2015	2014
Average Active Electric Connections For The Period		
Residential	79,800	78,200
Commercial and Industrial	12,500	12,300
Total Average Active Electric Connections For The Period	92,300	90,500
Customer Usage (GW-hrs)		
Residential	120.4	121.9
Commercial and Industrial	219.5	213.5
Total Customer Usage (GW-hrs)	339.9	335.4

For the three months ended June 30, 2015 the electric distribution systems' usage totalled 339.9 GW-hrs, as compared to 335.4 GW-hrs for the same period in 2014, an increase of 4.5 GW-hrs.

For the three months ended June 30, 2015, the electric distribution systems' revenue from utility electricity sales totalled U.S. \$37.9 million, as compared to U.S. \$40.8 million during the same period in 2014, a decrease of U.S. \$2.9 million, or 7.1%. For the three months ended June 30, 2015, fuel and purchased power costs for the electric distribution systems totalled U.S. \$20.5 million, as compared to U.S. \$22.7 million during the same period in 2014, a decrease of U.S. \$2.2 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 June 30, 2015, net utility sales for the electric distribution systems were U.S. \$17.4 million, as compared to U.S. \$18.1 million during the same period in 2014, a decrease of U.S. \$0.7 million, or 4%.

Natural Gas Distribution Systems

	Three months ended June 30,	
	2015	2014
Average Active Natural Gas Connections For The Period		
Residential	248,500	250,200
Commercial and Industrial	26,700	26,300
Total Average Active Natural Gas Connections For The Period	275,200	276,500
Customer Usage (MMBTU)		
Residential	3,342,000	3,710,000
Commercial and Industrial	2,582,000	2,695,000
Total Customer Usage (MMBTU)	5,924,000	6,405,000

For the three months ended June 30, 2015, usage at the natural gas distribution systems totalled 5,924,000 MMBTU, as compared to 6,405,000 MMBTU during the same period in 2014, a decrease of 481,000 MMBTU. The decrease in natural gas usage, as compared to the same period in 2014, can primarily be attributed to a decrease in volumes at the Midstates Gas System, primarily due to a 24% decrease in heating degree days within the Midstates service territories. A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees Fahrenheit (18 degrees Celsius).

For the three months ended June 30, 2015, revenue excluding transportation revenue from natural gas sales and distribution totalled U.S. \$51.1 million, as compared to U.S. \$60.1 million during the same period in 2014, a decrease of U.S. \$9.0 million. For the three months ended June 30, 2015, natural gas purchases totalled U.S. \$16.4 million, as compared with U.S. \$30.2 million for the same period in 2014, a decrease of U.S. \$13.8 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 June 30, 2015, net utility sales for the natural gas distribution systems, excluding transportation, totalled U.S. \$34.7 million, as compared to U.S. \$29.9 million during the same period in 2014, an increase of U.S. \$4.8 million. The increase in net utility sales, excluding transportation, can be primarily attributed to the implementation of interim rates at the EnergyNorth Gas System, the recognition of additional revenue related to the implementation of the final rate case at the EnergyNorth Gas System in the amount of U.S. \$3.0 million representing the difference between interim rates previously granted and final rates retroactive to November 1, 2014, and the implementation of final rates as a result of the general rate case at the Missouri and Illinois Gas Systems.

For the three months ended June 30, 2015, revenue from gas transportation sales totalled U.S. \$6.7 million, as compared to U.S. \$5.2 million during the same period in 2014, an increase of U.S. \$1.5 million. The increase in gas transportation sales can be primarily attributed to increased transportation revenues at the EnergyNorth, primarily due to the implementation of interim rates at the system as a result of the general rate case as compared to the same period in the prior year.

Water and Wastewater Distribution Systems

Three months ended June 30,

	2015	2014
Average Active Connections For The Period		
Wastewater connections	40,000	38,800
Water distribution connections	58,700	57,400
Total Average Active Connections For The Period	98,700	96,200
Gallons Provided (millions of gallons)		
Wastewater treated (millions of gallons)	562	515
Water sold (millions of gallons)	2,332	2,117
Total Gallons Provided (millions of gallons)	2,894	2,632

During the three months ended June 30, 2015, the water and wastewater distribution systems provided approximately 2,332 million gallons of water to its customers and treated approximately 562 million gallons of wastewater, as compared to 2,117 million gallons of water and 515 million gallons of wastewater during the same period in 2014. The increase in the gallons of water provided to customers can be primarily attributed to increased demand in certain Arizona service territories.

The increase in average active wastewater and water distribution connections can be primarily attributed to the acquisition of the White Hall Water System on May 30, 2014.

For the three months ended June 30, 2015, revenue from wastewater treatment and water distribution totalled U.S. \$6.8 million and U.S. \$8.8 million, respectively, as compared to U.S. \$6.4 million and U.S. \$8.7 million, respectively, during the same period in 2014. The increase in total wastewater treatment and water distribution 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, and an increase in demand in certain Arizona service territories.

Other Revenue

For the three months ended June 30, 2015, other revenue totalled U.S. \$1.0 million, as compared to U.S. \$0.7 million during the same period in 2014. The other revenue consists of operations and maintenance services provided by the Peach State Gas System through the privatization contract for Fort Benning and water heater rental service revenue in the New England Gas System territory. The year over year increase is primarily attributed to additional work performed at Fort Benning in the current year.

Operating Expenses

For the three months ended June 30, 2015, operating expenses, excluding electricity purchases, totalled U.S. \$40.8 million, as compared to U.S. \$41.9 million during the same period in 2014, a decrease of U.S. \$1.1 million. The major factors resulting in the decrease in the Distribution Group's operating expenses in the three months ended June 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 June 30, 2015	
Comparative Prior Period Operating Expenses	\$	41.9
Significant Changes:		
Decrease in operating expenses at the EnergyNorth Gas System		(2.4)
Increase in operating expenses due to acquisition of the White Hall Water and Waste System on May 30, 2014		0.3
Increase in operating expenses at the Peach State, the New England Gas, and the Calpeco Electric Systems		0.8
Other		0.2
Current Period Operating Expenses	\$	40.8

The decrease in operating expenses at the EnergyNorth Gas System can primarily be attributed to a decrease in bad debt expense due to improved collections processes as compared to the same period in the prior year.

The increase in operating expenses at the Peach State Gas System, New England Gas System, and Calpeco Electric System can be primarily attributed to increased administrative costs related to open dockets at the Calpeco Electric System, and increased labour and collection expenses at the Peach State Gas System and New England Gas System.

	Six months ended June 30,		Six months ended June 30,	
	2015 U.S. \$ (millions)	2014 U.S. \$ (millions)	2015 Can \$ (millions)	2014 Can \$ (millions)
Revenue				
Utility electricity sales and distribution	\$ 94.0	\$ 92.7	\$ 116.2	\$ 101.7
Less: Cost of Sales – Electricity	(57.9)	(53.7)	(71.5)	(58.9)
Net Utility Sales - Electricity	\$ 36.1	\$ 39.0	\$ 44.7	\$ 42.8
Utility natural gas sales and distribution	225.8	239.8	279.2	263.8
Less: Cost of Sales – Natural Gas	(128.1)	(156.8)	(158.3)	(172.5)
Net Utility Sales - Natural Gas	\$ 97.7	\$ 83.0	\$ 120.9	\$ 91.3
Net Utility Sales - Water Distribution & Wastewater Treatment	29.1	28.2	36.3	31.0
Gas Transportation	17.1	13.9	21.0	15.3
Other Revenue	2.8	1.3	3.5	1.5
Net Utility Sales	\$ 182.8	\$ 165.4	\$ 226.4	\$ 181.9
Operating expenses	(86.1)	(81.0)	(106.2)	(88.8)
Other income	1.6	1.7	2.0	1.8
Distribution Group operating profit	\$ 98.3	\$ 86.1	\$ 122.2	\$ 94.9

2015 Six Month Operating Results

For the six months ended June 30, 2015, the Distribution Group reported an operating profit of U.S. \$98.3 million, as compared to U.S. \$86.1 million for the comparable period in the prior year, an increase of U.S. \$12.2 million or 14.2%. The increase is primarily due to the implementation of interim rates at the EnergyNorth Gas System, the recognition of additional revenue related to the implementation of the final rate case at the EnergyNorth Gas System representing the difference between interim rates granted and final rates retroactive to November 1, 2014, the implementation of final rates as a result of the general rate case at the Missouri and Illinois Gas Systems, increased rates at the Peach State Gas System as a result of the GRAM filing and Pipeline Replacement Program, and below seasonal temperatures experienced in the New Hampshire service territory, 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 \$122.2 million, as compared to \$94.9 million for the comparable period in the prior year. In addition to the factors discussed below, operating profit measured in Canadian dollars increased by \$15.1 million due to a stronger U.S. dollar.

Electric Distribution Systems

Six months ended June 30,
2015 2014

Average Active Electric Connections For The Period		
Residential	79,800	78,100
Commercial and Industrial	12,500	12,300
Total Average Active Electric Connections For The Period	92,300	90,400
Customer Usage (GW-hrs)		
Residential	287.1	292.8
Commercial and Industrial	440.8	437.1
Total Customer Usage (GW-hrs)	727.9	729.9

For the six months ended June 30, 2015, the electric distribution systems' usage totalled 727.9 GW-hrs, as compared to 729.9 GW-hrs for the same period in 2014, a decrease of 2.1 GW-hrs.

For the six months ended June 30, 2015, the electric distribution systems' revenue from utility electricity sales totalled U.S. \$94.0 million, as compared to U.S. \$92.7 million during the same period in 2014, an increase of U.S. \$1.3 million. For the six months ended June 30, 2015, purchased power costs for the electric distribution systems totalled U.S. \$57.9 million, as compared to U.S. \$53.7 million for the same period in 2014, an increase of U.S. \$4.2 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 six months ended June 30, 2015, net utility sales for the electric distribution systems were U.S. \$36.1 million, as compared to U.S. \$39.0 million for the same period in 2014, a decrease of U.S. \$2.9 million. Adjusting for the retroactive recognition of \$2.5 million for new revenues granted under Granite State Electric System rate case implemented in the first quarter of 2014, revenues were consistent year over year.

Natural Gas Distribution Systems

Six months ended June 30,
2015 2014

Average Active Natural Gas Connections For The Period		
Residential	250,500	251,200
Commercial and Industrial	27,100	26,300
Total Average Active Natural Gas Connections For The Period	277,600	277,500
Customer Usage (MMBTU)		
Residential	13,397,000	13,986,000
Commercial and Industrial	8,696,000	8,566,000
Total Customer Usage (MMBTU)	22,093,000	22,552,000

For the six months ended June 30, 2015, customer usage at the natural gas distribution systems totalled 22,093,000 MMBTU, as compared to 22,552,000 MMBTU during the same period in 2014, a decrease of 459,000 MMBTU. The decrease in natural gas usage, as compared to the same period in 2014, can be primarily attributed to a decline in usage at the MidStates Gas System and Peach State Gas System as compared to the same period in the prior year, primarily due to a 10% decrease in heating degree days within the service territories.

For the six months ended June 30, 2015, revenue from natural gas sales and distribution totalled U.S. \$225.8 million, as compared to U.S. \$239.8 million during the same period in 2014, a decrease of U.S. \$14.0 million. For the six months ended June 30, 2015, natural gas purchases totalled U.S. \$128.1 million, as compared to U.S. \$156.8 million for the same period in 2014, a decrease of U.S. \$28.7 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 six months ended June 30, 2015, net utility sales, excluding transportation, for the natural gas distribution

systems totalled U.S. \$97.7 million, as compared to U.S. \$83.0 million during the same period in 2014, an increase of U.S. \$14.7 million. The increase in net utility sales, excluding transportation, can be primarily attributed to the implementation of interim rates at the EnergyNorth Gas System, the recognition of additional revenue related to the implementation of the final rate case at the EnergyNorth Gas System in the amount of U.S. \$3.0 million representing the difference between interim rates previously granted and final rates retroactive to November 1, 2014, and the implementation of final rates as a result of the general rate case at the Missouri and Illinois Gas Systems.

For the six months ended June 30, 2015, revenue from gas transportation sales totalled U.S. \$17.1 million, as compared to U.S. \$13.9 million during the same period in 2014, an increase of U.S. \$3.2 million. The Midstates Gas System contributed U.S. \$2.2 million to the total transportation revenues for the six months ended June 30, 2015, the EnergyNorth Gas System contributed U.S. \$8.8 million, the Peach State Gas System contributed U.S. \$1.4 million, and the New England Gas System contributed U.S. \$4.7 million.

Water and Wastewater Distribution Systems

	Six months ended June 30,	
	2015	2014
Average Active Connections For The Period		
Wastewater connections	40,000	38,000
Water distribution connections	58,800	56,700
Total Average Active Connections For The Period	98,800	94,700
Gallons Provided		
Wastewater treated (millions of gallons)	1,139	1,061
Water sold (millions of gallons)	4,009	3,824
Total Gallons Provided	5,148	4,885

During the six months ended June 30, 2015, the water and wastewater distribution systems provided approximately 4,009 million gallons of water to its customers and treated approximately 1,139 million gallons of wastewater, as compared to 1,061 million gallons of wastewater and 3,824 million gallons of water during the same period in 2014. Total average active connections for the period increased by 4,100 to 98,800 from 94,700 in the same period in the prior year. The increase can be primarily attributed to the acquisition of the White Hall Water and Sewer System on May 30, 2014 which serves approximately 1,900 water distribution and 2,400 wastewater treatment customers.

For the six months ended June 30, 2015, revenue from wastewater treatment and water distribution totalled U.S. \$13.6 million and U.S. \$15.5 million, respectively, as compared to U.S. \$12.6 million and U.S. \$15.6 million, respectively, during the same period in 2014. The increase in total wastewater treatment and water distribution 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, and an increase in demand in certain Arizona service territories.

Other Revenue

For the six months ended June 30, 2015, other revenue totalled U.S. \$2.8 million, as compared to U.S. \$1.3 million during the same period in 2014. The other revenue primarily consists of operations and maintenance services provided by the Peach State Gas System through the privatization contract for Fort Benning, and water heater rental service revenue in the New England Gas System territory. The year over year increase is primarily attributed to additional work performed at Fort Benning in the current year.

Operating Expenses

For the six months ended June 30, 2015, operating expenses, excluding electricity purchases, totalled U.S. \$86.1 million, as compared to U.S. \$81.0 million during the same period in 2014, an increase of U.S. \$5.1 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)	Six months ended June 30, 2015	
Comparative Prior Period Operating Expenses	\$	81.0
Significant Changes:		
Increase in operating expenses at the New England Gas System		1.8
Increase in operating expenses at the Peach State Gas System		1.2
Increase in operating expenses at the CalPeco Electric System		1.0
Acquisition of the New Hampshire Gas		0.7
Acquisition of the White Hall Water System		0.6
Decrease in operating expenses at the EnergyNorth Gas System		(1.5)
Other		1.3
Current Period Operating Expenses	\$	86.1

The increase in operating expenses at the New England Gas System can primarily be attributed to a decreased number of capital-related work completed due to extreme winter weather conditions, which resulted in a decreased capitalization rate as compared to the same period in 2014.

The increase in operating expenses at the Peach State Gas System can be primarily attributed to an increase in cost of sales and administrative expenses for work completed at Fort Benning, as compared to the six months ended June 30, 2014.

The increase in operating expenses at the Calpeco Electric System can be primarily attributed to increased administrative costs related to open dockets.

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 \$1.3 million, as compared to the similar period in 2014.

The decrease in operating expenses at the EnergyNorth Gas System can primarily be attributed to a decrease in bad debt expense due to improved collections processes.

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
Rate Cases Completed in the Quarter				
EnergyNorth System	New Hampshire	General Rate Case	\$16.1	Application filed in August 2014; a temporary rate increase was approved on November 21, 2014 allowing a U.S. \$7.4 million interim increase effective December 1, 2014, retroactive to November 1, 2014 upon approval of permanent rates. A final permanent rates decision was issued in June 2015, effective July 1 2015, allowing for a \$12.4 million rate increase effective July 1 2015
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 Q1 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.
Missouri Natural Gas System	Missouri	Infrastructure System Replacement Surcharge	\$0.4	Application filed in June 2015 seeking a U.S. \$0.4 million revenue increase. A final rate decision is expected in Q4 2015.
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.

Rate Cases Completed in the Quarter

On August 1, 2014, the EnergyNorth Natural Gas System in New Hampshire filed an application for an increase in revenue of U.S. \$16.1 million, or approximately 9.6%. A temporary rate increase was approved on November 21, 2014, allowing a U.S. \$7.4 million interim rate increase effective December 1, 2014, retroactive to November 2014 upon approval of permanent rates. On June 26, 2015, an Order was issued approving a settlement agreement allowing for a U.S. \$12.4 million revenue increase effective July 1, 2015.

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 return on equity of 10.5% and a debt/equity structure of 45%/55%. The previous test year ended December 31, 2011. Expected implementation of the new permanent rates is in the first quarter of 2016.

Related to the above CalPeco Electric System rate application is a pending application 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 seeks 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 for authorization to enter into a 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. These two applications will 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.

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 is expected in Q4 2015 with an expected effective date of November 1, 2015.

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. 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 return on equity of 10.4% and a debt/equity structure of 45%/55%, resulting in an overall rate of return on rate base of 8.6%. An expected decision on this application is expected in Q2 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 California Public Utilities Commission ("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 has been 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. A regulatory hearing is now scheduled for October 19, 2015. A decision on the Montana application is also expected in the fourth quarter of 2015.

TRANSMISSION BUSINESS GROUP

In November 2014, the Transmission Group 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 30-inch or 36-inch 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 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 is planned for October, 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.

APUC: Corporate and Other Expenses

(all dollar amounts in \$ millions)	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Corporate and other expenses:				
Administrative expenses	\$ 8.5	\$ 8.2	\$ 19.0	\$ 16.0
(Gain)/Loss on foreign exchange	—	0.8	(1.3)	(0.9)
Interest expense	16.5	16.2	33.2	32.4
Interest, dividend and other Income ¹	(0.5)	(0.8)	(1.0)	(2.0)
Write down of long lived assets	0.4	0.3	0.3	0.7
Acquisition-related costs	0.5	0.2	0.8	0.5
(Gain)/Loss on derivative financial instruments	(2.4)	1.3	(2.5)	1.0
Income tax expense	9.5	5.8	28.9	17.7

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

2015 Second Quarter Corporate and Other Expenses

During the three months ended June 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 June 30, 2015, interest expense totalled \$16.5 million, as compared to \$16.2 million in the same period in 2014. The increased interest expense is a result of new indebtedness incurred in the second quarter of 2015.

For the three months ended June 30, 2015, interest, dividend and other income totalled \$0.5 million, as compared to \$0.8 million in the same period in 2014, a decrease of \$0.3 million due to no dividends received from Kirkland and Cochrane investments in 2015.

For the three months ended June 30, 2015, acquisition-related costs totalled \$0.5 million as compared to \$0.2 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 \$9.5 million was recorded in the three months ended June 30, 2015, as compared to an income tax expense of \$5.8 million during the same period in 2014. The increase in income tax expense for the three months ended June 30, 2015, is primarily due to a one-time non-cash charge of \$2.7 million to deferred income taxes as a result of an agreement reached with the Canada Revenue Agency ("CRA") related to the Unit Exchange Transaction (see Operational Risk Management - Tax Risk and Uncertainty), increased earnings from operations, and a stronger U.S. dollar.

2015 Six Month Corporate and Other Expenses

During the six months ended June 30, 2015, administrative expenses totalled \$19.0 million, as compared to \$16.0 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 six months ended June 30, 2015, interest expense totalled \$33.2 million, as compared to \$32.4 million in the same period in 2014. The increased interest expense is a result of new debt issued midway through the first quarter of 2014 (whereby the full period interest expense was recorded in 2015) and new debt issued in the second quarter of 2015.

For the six months ended June 30, 2015, interest, dividend and other income totalled \$1.0 million, as compared to \$2.0 million in the same period in 2014, a decrease of \$1.0 million due to no dividends received from Kirkland and Cochrane investments in 2015.

For the six months ended June 30, 2015, acquisition-related costs totalled \$0.8 million as compared to \$0.5 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 \$28.9 million was recorded in the six months ended June 30, 2015, as compared to an income tax expense of \$17.7 million during the same period in 2014. The increase in income tax expense for the six months ended June 30, 2015, is primarily due to 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) , increased earnings from operations, increased deferred taxes on HLBV income, a stronger U.S. dollar, 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.

(all dollar amounts in \$ millions)	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Net earnings attributable to Shareholders	\$ 19.9	\$ 14.6	\$ 63.0	\$ 50.4
Add (deduct):				
Net earnings attributable to the non-controlling interest, exclusive of HLBV	0.5	0.3	1.1	4.1
Loss from discontinued operations	0.7	0.7	0.7	0.4
Income tax expense	9.5	5.8	28.9	17.7
Interest expense	16.5	16.2	33.2	32.4
Other gains	(1.3)	—	(2.4)	—
Non-cash write downs	0.4	0.3	0.3	0.7
Acquisition costs	0.5	0.2	0.8	0.5
(Gain) / Loss on derivative financial instruments	(2.4)	1.3	(2.5)	1.0
Realized gain / (loss) on energy derivative contracts	—	—	0.6	4.0
(Gain) / Loss on foreign exchange	—	0.8	(1.3)	(0.9)
Depreciation and amortization	36.8	26.2	73.2	54.5
Adjusted EBITDA	\$ 81.1	\$ 66.4	\$ 195.6	\$ 164.8

Hypothetical Liquidation at Book Value (“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 power generation facilities. The value of net tax attributes earned in the three and six months ended June 30, 2015, amounted to approximately \$8.0 million and \$16.9 million, respectively.

For the six months ended June 30, 2015, Adjusted EBITDA totalled \$195.6 million, as compared to \$164.8 million during the same period in 2014, an increase of \$30.8 million. For the quarter ended June 30, 2015, Adjusted EBITDA totalled \$81.1 million as compared to \$66.4 million, an increase of \$14.7 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 June 30	Six months ended June 30
Comparative Prior Period Adjusted EBITDA	\$ 66.4	\$ 164.8
Significant Changes:		
Decrease in hydrology resources at all regions except Ontario, coupled with decreased customer load and retail pricing in the Maritime region	(0.8)	(2.4)
Decrease in wind resource partially offset by gains on periodic production shortfalls under the power hedges and higher pricing realized on sales of the unhedged portion of energy produced	(2.4)	(1.5)
Start of commercial operations of the St. Damase (Q4'14) and Morse (Q2'15) Wind Facilities.	3.3	5.0
Start of commercial operations at the Cornwall (Q1'14) and Bakersfield I (Q2'15) Solar Facilities.	0.7	1.8
Higher realized prices on sale of Renewable Energy Credits offset by decreased production	(0.1)	1.2
Lower realized prices at the Sanger and Windsor Locks Thermal Facilities combined with lower production	(0.5)	(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	6.7	13.7
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 revenues at Peach State Gas System's Fort Benning operations	0.3	1.6
Increase in administrative expense	(0.3)	(3.0)
Increased results from the stronger U.S. dollar	7.6	18.9
Other	0.2	(1.4)
Current Period Adjusted EBITDA	\$ 81.1	\$ 195.6

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:

(all dollar amounts in \$ millions)	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Net earnings attributable to Shareholders	\$ 19.9	\$ 14.6	\$ 63.0	\$ 50.5
Add (deduct):				
(Gain) / Loss from discontinued operations, net of tax	0.7	0.7	0.7	0.4
(Gain) / Loss on derivative financial instruments, net of tax	(1.4)	0.8	(1.5)	0.6
Realized gain / (loss) on derivative financial instruments, net of tax	(0.4)	(0.4)	(0.3)	1.7
Write-down on long lived assets	0.4	0.3	0.3	0.7
(Gain) / Loss on foreign exchange, net of tax	—	0.5	(0.8)	(0.6)
Deferred tax expense due to CRA agreement related to the Unit Exchange Transaction	2.7	—	2.7	—
Acquisition costs, net of tax	0.3	0.1	0.5	0.3
Adjusted net earnings	\$ 22.2	\$ 16.6	\$ 64.6	\$ 53.6
Adjusted net earnings per share	\$ 0.08	\$ 0.07	\$ 0.25	\$ 0.24

For the three months ended June 30, 2015, adjusted net earnings totalled \$22.2 million, as compared to adjusted net earnings of \$16.6 million, an increase of \$5.6 million as compared to the same period in 2014. The increase in adjusted net earnings for the three months ended June 30, 2015, is primarily due to higher income from operations partially offset by higher interest expense, as well as depreciation and amortization expense as compared to the same period in 2014.

For the six months ended June 30, 2015, adjusted net earnings totalled \$64.6 million, as compared to adjusted net earnings of \$53.6 million, an increase of \$11.0 million as compared to the same period in 2014. The increase in adjusted net earnings for the three months ended June 30, 2015, is primarily due to higher income from operations partially offset by higher interest 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:

(all dollar amounts in \$ millions)	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Cash flows from operating activities	\$ 98.8	84.5	\$ 91.4	\$ 99.4
Add (deduct):				
Changes in non-cash operating items	(45.4)	(45.9)	51.8	12.5
Cash used in discontinued operations	1.3	0.3	1.3	0.5
Production based cash contributions from non-controlling interests	—	—	10.8	9.0
Acquisition costs	0.5	0.2	0.8	0.5
Adjusted funds from operations	\$ 55.2	\$ 39.1	\$ 156.1	\$ 121.9
Adjusted funds from operations per share	\$ 0.22	\$ 0.17	\$ 0.63	\$ 0.57

For the three months ended June 30, 2015, adjusted funds from operations totalled \$55.2 million, as compared to adjusted funds from operations of \$39.1 million, an increase of \$16.1 million as compared to the same period in 2014.

For the six months ended June 30, 2015, adjusted funds from operations totalled \$156.1 million, as compared to adjusted funds from operations of \$121.9 million, an increase of \$34.2 million as compared to the same period in 2014.

Summary of Property, Plant, and Equipment

(all dollar amounts in \$ millions)	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
GENERATION GROUP				
Renewable	\$ 8.1	64.7	\$ 28.3	\$ 76.0
Thermal	0.4	1.6	0.6	3.0
Total Generation Business Group	\$ 8.5	\$ 66.3	\$ 28.9	\$ 79.0
DISTRIBUTION GROUP	26.8	35.0	\$ 50.3	\$ 54.5
Corporate	1.2	1.2	2.6	45.9
Total	\$ 36.5	\$ 102.5	\$ 81.8	\$ 179.4

The company's consolidated capital expenditure plan for 2015 is approximately \$273.0 million. The Generation Group expects to invest approximately \$107.0 million primarily in connection with its development portfolio. The Distribution Group expects to invest approximately \$159.0 million (U.S. \$127.0 million) primarily to improve the reliability and efficiency of its gas and electric utility distribution systems. The Transmission Group expects to invest approximately \$7.0 million (U.S. \$5.8 million) for the natural gas pipeline transmission project.

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 Second Quarter Property Plant and Equipment Expenditures

During the three months ended June 30, 2015, the Generation Group incurred capital expenditures of \$8.5 million, as compared to \$66.3 million during the comparable period in 2014.

During the three months ended June 30, 2015, the Generation Group's Renewable Energy Division spent \$8.1 million in capital expenditures, as compared to \$64.7 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 \$0.4 million, as compared to \$1.6 million in the comparable period in 2014.

During the three months ended June 30, 2015, the Distribution Group invested \$26.8 million (U.S. \$21.8 million) in capital expenditures, as compared to \$35.0 million (U.S. \$31.9 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.

2015 Six Month Property Plant and Equipment Expenditures

During the six months ended June 30, 2015, the Generation Group incurred capital expenditures of \$28.9 million, as compared to \$79.0 million during the comparable period in 2014.

During the six months ended June 30, 2015, the Generation Group's Renewable Energy Division spent \$28.3 million in capital expenditures, as compared to \$76.0 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 \$0.6 million, as compared to \$3.0 million in the comparable period in 2014.

During the six months ended June 30, 2015, the Distribution Group invested \$50.3 million (U.S. \$41.0 million) in capital expenditures, as compared to \$54.5 million (U.S. \$49.7 million) during the comparable period in 2014. The Distribution Group's capital expenditures primarily related to a compressed natural gas project, a new training center, 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 \$7.9 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	\$ 7.9	0.5	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 have been declassified and removed from the CEHQ's registry, while three others have been reclassified to Class E (Very Low Consequence) dams, from higher classes. Upon the recommendation of third party engineers, the Generation Group has requested a postponement of 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 June 30, 2015, under the Facilities:

(all dollar amounts in \$ millions)	As at June 30, 2015				As at Dec 31 2014
	Corporate	Generation Group	Distribution Group	Total	Total
Committed Facilities	\$ 65.0	\$ 350.0	\$ 249.8	\$ 664.8	\$ 647.0
Funds drawn on Facilities	—	(102.7)	(42.8)	(145.5)	(47.3)
Letters of Credit issued	(11.7)	(95.5)	(9.9)	(117.1)	(113.8)
Funds available for draws on the Facilities	\$ 53.3	\$ 151.8	\$ 197.1	\$ 402.2	\$ 485.9
Cash on Hand				26.3	9.3
Total liquidity and capital reserves	\$ 53.3	\$ 151.8	\$ 197.1	\$ 428.5	\$ 495.2

As at June 30, 2015, the Company's \$65.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility"), was undrawn and had \$11.7 million of outstanding letters of credit. The facility matures on November 19, 2016, and is subject to customary covenants.

As at June 30, 2015, the Generation Group's \$350.0 million Credit Facility ("Generation Credit Facility") had drawn \$102.7 million and had \$95.5 million in outstanding letters of credit. During the quarter the Generation Group extended the maturity date of the Generation Credit Facility by one-year to July 31, 2019.

As at June 30, 2015, the Distribution Group's \$249.8 million (U.S. \$200.0 million) senior unsecured revolving credit facility (the "Distribution Credit Facility") had drawn \$42.8 million (U.S. \$34.3 million) and had \$9.9 million (U.S. \$7.9 million) of outstanding letters of credit. The facility matures on September 30, 2018, and is subject to customary covenants.

Long Term Debt

During the quarter the Generation Group repaid U.S. \$76.0 million on its Shady Oaks Wind secured debt facility representing the full outstanding balance. Correspondingly, all security previously held against the facility has been released.

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 subsequent to the quarter end 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.

As at June 30, 2015, the weighted average tenor of APUC's total long term debt is approximately 8.8 years with an average interest rate of 4.9%.

Contractual Obligations

Information concerning contractual obligations as of June 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	1,449.0	8.6	80.4	308.1	1,051.9
Advances in aid of construction	87.4	1.2			86.2
Interest on long-term debt obligations	564.3	71.4	138.7	110.8	243.4
Purchase obligations	153.0	153.0			
Environmental obligation	72.4	13.7	31.2	4.1	23.4
Derivative financial instruments:					
Cross currency swap	55.6	2.7	5.0	4.0	43.9
Interest rate forward	4.2	—	—	4.2	—
Interest rate swap	0.5	0.5	—	—	—
Energy derivative contracts	1.5	1.5	—	—	—
Capital projects	18.0	10.5	7.5	—	—
Long Term Service agreements	663.4	32.5	67.6	66.2	497.1
Purchased power	405.7	63.4	105.3	120.1	116.9
Gas delivery, service and supply agreements	282.8	60.0	72.2	63.5	87.1
Operating leases	125.3	5.9	9.8	8.9	100.7
Other Obligations	45.8	10.6	0.9	—	34.3
Total obligations	3,928.9	435.5	518.6	689.9	2,284.9

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at June 30, 2015, APUC had 239,546,373 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 June 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 June 30, 2015, 66,706,739 common shares representing approximately 28% of total shares outstanding had been registered with the Reinvestment Plan. During the quarter ended June 30, 2015, 619,468 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on July 15, 2015, an additional 907,017 common shares were issued under the Reinvestment Plan.

Emera shareholdings and subscription receipts

As at August 13, 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. APUC believes issuance of

shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

Share Based Compensation Plans

For the three and six months ended June 30, 2015, APUC recorded \$1.2 million and \$2.1 million (2014 - \$0.6 million and \$1.0 million) in total share-based compensation expense. The compensation expense is recorded as part of administrative expenses in the unaudited interim consolidated statement of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at June 30, 2015, total unrecognized compensation costs related to non-vested options and share unit awards were \$5.0 million and \$3.1 million respectively, and are expected to be recognized over a period of 2.1 years and 1.9 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 June 30, 2015, a total of 5,210,621 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 shares at the election of APUC.

The plan provides for settlement in cash or shares at the election of the Company. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Company expects to settle the remaining PSUs in shares. As a result, the PSUs continue to be accounted for as equity awards.

As at June 30, 2015, a total of 568,695 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 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 June 30, 2015, a total of 131,055 DSUs had been granted under the DSU plan.

Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares.

As at June 30, 2015, a total of 288,269 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 six months ended June 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. \$1.9 million and U.S. \$3.5 million, respectively (2014 - U.S. \$2.2 million and U.S. \$6.2 million). For the three and six months ended June 30, 2015, Liberty Utilities purchased natural gas amounting to U.S. \$1.2 million and U.S. \$1.3 million, respectively (2014 - U.S. \$1.8 million and U.S. \$4.7 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 June 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 \$0.01 million. During the three and six months ended June 30, 2015, APUC reimbursed direct costs in connection with the use of the aircraft of \$0.2 million and \$0.4 million (2014 - \$0.09 million and \$0.3 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 six months ended June 30, 2015 were \$nil (2014 - \$0.09 million and \$0.2 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 six months ended June 30, 2015 APUC paid \$Nil and \$0.02 million (2014 - \$0.03 million and \$0.07 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.

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 has no amounts outstanding as at June 30, 2015. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The Generation Credit Facility had \$102.7 million outstanding as at June 30, 2015. As a result, a 100 basis point change in the variable rate charged would impact interest expense by \$1.0 million annually.
- The Distribution Credit Facility had \$42.8 million outstanding as at June 30, 2015. As a result, a 100 basis point change in the variable rate charged would impact interest expense by \$0.4 million annually.
- The Generation Group is party to an interest rate swap whereby the group pays a fixed interest rate of 4.47% on a notional amount of \$60.5 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. This interest rate swap is not being accounted for as a hedge and, consequently, changes in fair value are recorded in earnings as they occur. As a result, a 100 basis point change in the variable rate would impact derivative gains/losses by \$0.01 million.

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 June 30, 2015, APUC and its subsidiaries had a combined \$402.2 million of committed and available revolving credit facilities remaining and \$26.3 million of cash resulting in \$428.5 million of total liquidity and capital reserves.

APUC currently pays a dividend of U.S. \$0.385 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 \$1,449.0 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. 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.

Dimos and Katsekas Breach of Contract Claim

On September 30, 2013, Dimos and Katsekas, previous owners of the Clement Dam Hydroelectric, LLC. ("Clement Dam Hydro Facility"), filed a demand for arbitration with Algonquin Power Fund (America) Inc. ("APFA") alleging breach of the Purchase Agreement and Royalty Agreement. The claim is for U.S. \$1.3 million for alleged breach of such agreements and U.S. \$0.2 million for alleged unpaid royalties. The plaintiffs have demanded arbitration pursuant to such agreements.

Arbitration hearings occurred in May 2015. The parties are awaiting the decision of the arbitrator. The litigation has been stayed pending the outcome of the arbitration proceeding. Subsequent to the quarter, this claim was resolved.

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, the Company's results for the three and six months period ended June 30, 2015 reflect a \$2.7 million net non-cash charge to deferred income tax expense.

Quarterly Financial Information

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

(all dollar amounts in \$ millions except per share information)	3rd Quarter 2014	4th Quarter 2014	1st Quarter 2015	2nd Quarter 2015
Revenue	\$ 151.9	\$ 259.3	381.9	196.2
Adjusted EBITDA	41.4	84.3	114.5	81.1
Net earnings / (loss) attributable to shareholders from continuing operations	(6.1)	33.1	43.1	20.6
Net earnings / (loss) attributable to shareholders	(6.3)	31.6	43.1	19.9
Net earnings / (loss) per share from continuing operations	(0.04)	0.13	0.16	0.07
Net earnings / (loss) per share	(0.04)	0.13	0.16	0.07
Adjusted net earnings / (loss)	(0.4)	35.2	42.5	22.2
Adjusted net earnings / (loss) per share	(0.01)	0.14	0.17	0.08
Total Assets	3,799.3	4,105.1	4,531.4	4,396.5
Long term liabilities ¹	1,404.3	1,271.2	1,482.7	1,440.3
Dividend declared per common share	0.10	0.10	0.11	0.12
	3rd Quarter 2013	4th Quarter 2013	1st Quarter 2014	2nd Quarter 2014
Revenue	\$ 127.9	\$ 205.3	\$ 343.5	188.6
Adjusted EBITDA	40.5	67.6	97.5	66.4
Net earnings / (loss) attributable to shareholders from continuing operations	6.3	19.8	35.6	15.2
Net earnings / (loss) attributable to shareholders	6.0	13.1	35.9	14.6
Net earnings / (loss) per share from continuing operations	0.02	0.09	0.16	0.06
Net earnings / (loss) per share	0.02	0.06	0.17	0.06
Adjusted net earnings	6.9	18.5	36.8	16.6
Adjusted net earnings per share	0.03	0.08	0.17	0.07
Total Assets	3,149.2	3,469.3	3,644.3	3,553.6
Long term liabilities ¹	1,084.8	1,248.3	1,400.9	1,381.0
Dividend declared per common share	0.09	0.09	0.09	0.09

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 \$127.9 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 June 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 June 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 six months ended June 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 six months period ended June 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 six months period ended June 30, 2015, was a reduction of depreciation expense of \$1.3 million and \$0.9 million, respectively. There was no impact on net earnings per share. 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)

	June 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 26,284	\$ 9,273
Accounts receivable, net (note 4)	155,118	188,573
Natural gas in storage	16,682	31,550
Supplies and consumables inventory	13,724	11,825
Regulatory assets (note 5)	26,925	61,645
Prepaid expenses	18,994	10,431
Long-term investments (note 6)	334	2,966
Deferred income taxes (note 15)	22,540	7,210
Income taxes receivable (note 15)	725	568
Derivative instruments (note 20)	9,650	10,688
Assets held for sale	6,115	—
	297,091	334,729
Property, plant and equipment, net	3,503,510	3,278,422
Intangible assets, net	70,471	54,011
Goodwill	99,715	92,328
Regulatory assets (note 5)	192,140	186,669
Derivative instruments (note 20)	53,322	31,782
Long-term investments (note 6)	121,433	43,279
Deferred income taxes (note 15)	38,232	57,065
Other assets	20,589	26,796
	\$ 4,396,503	\$ 4,105,081

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	June 30, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	\$ 20,233	\$ 68,540
Accrued liabilities	133,127	199,374
Dividends payable (note 12)	32,871	25,395
Regulatory liabilities (note 5)	33,963	20,590
Long-term liabilities (note 7)	8,579	9,130
Pension and other post-employment benefits (note 8)	359	333
Other long-term liabilities (note 9)	42,202	49,303
Derivative instruments (note 20)	4,708	5,183
Preferred shares, Series C	1,044	1,085
Income taxes liability (note 15)	3,262	3,633
Deferred income taxes (note 15)	226	3,702
	280,574	386,268
Long-term liabilities (note 7)	1,431,730	1,262,589
Regulatory liabilities (note 5)	108,371	101,166
Deferred income taxes (note 15)	187,133	130,758
Derivative instruments (note 20)	57,192	40,088
Pension and other post-employment benefits (note 8)	143,570	138,602
Other long-term liabilities (note 9)	176,658	179,468
Preferred shares, Series C	17,563	17,608
	2,122,217	1,870,279
Redeemable non-controlling interest (note 3(c))	11,231	12,146
Equity:		
Preferred shares	213,805	213,805
Common shares (note 10(a))	1,646,016	1,633,262
Subscription receipts	110,503	110,503
Additional paid-in capital	34,932	33,068
Deficit	(505,706)	(505,305)
Accumulated other comprehensive income (note 11)	146,123	34,213
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,645,673	1,519,546
Non-controlling interests	336,808	316,842
Total equity	1,982,481	1,836,388
Commitments and contingencies (note 18)		
Subsequent events (notes 7 and 12)		
	\$ 4,396,503	\$ 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 June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Revenue				
Regulated electricity distribution	\$ 46,567	\$ 44,451	\$ 116,156	\$ 101,712
Regulated gas distribution	71,012	71,263	300,224	279,126
Regulated water reclamation and distribution	19,172	16,381	36,251	31,022
Non-regulated energy sales	52,377	50,490	110,089	108,410
Other revenue	7,030	5,979	15,292	10,428
	196,158	188,564	578,012	530,698
Expenses				
Operating	66,631	60,172	137,791	117,013
Regulated electricity purchased	25,201	24,725	71,460	58,905
Regulated gas purchased	20,289	33,009	158,321	172,476
Non-regulated energy purchased	3,952	5,805	17,375	26,064
Administrative expenses	8,531	8,246	18,978	15,973
Depreciation of property, plant and equipment (note 1)	34,344	24,819	67,400	51,714
Amortization of intangible assets	1,244	1,072	2,457	2,151
Other amortization	1,243	314	3,361	664
Loss (gain) on foreign exchange	(43)	825	(1,286)	(931)
	161,392	158,987	475,857	444,029
Operating income from continuing operations	34,766	29,577	102,155	86,669
Interest expense	16,527	16,155	33,160	32,354
Interest, dividend, equity-method investment and other income	(1,530)	(2,360)	(3,985)	(4,554)
Other gains	(1,311)	—	(2,409)	—
Acquisition-related costs	459	224	758	497
Write-down on long-lived assets	377	289	272	665
Loss (gain) on derivative financial instruments (note 20(b)(iv))	(2,360)	1,343	(2,457)	980
	12,162	15,651	25,339	29,942
Earnings from continuing operations before income taxes	22,604	13,926	76,816	56,727
Income tax expense (note 15)				
Current	2,760	2,597	4,396	3,740
Deferred	6,723	3,213	24,478	13,940
	9,483	5,810	28,874	17,680
Earnings from continuing operations	13,121	8,116	47,942	39,047
Loss from discontinued operations, net of tax (note 18(c))	(713)	(705)	(713)	(432)
Net earnings	12,408	7,411	47,229	38,615
Net loss attributable to non-controlling interests (note 14)	(7,524)	(7,187)	(15,809)	(11,835)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	\$ 19,932	\$ 14,598	\$ 63,038	\$ 50,450
Series A and D Preferred shares dividend (note 12)	2,600	2,953	5,200	4,303
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp. (note 16)	\$ 17,332	\$ 11,645	\$ 57,838	\$ 46,147
Basic net earnings per share from continuing operations (note 16)	\$ 0.07	\$ 0.06	\$ 0.23	\$ 0.22
Basic net earnings per share (note 16)	0.07	0.06	0.23	0.22
Diluted net earnings per share from continuing operations (note 16)	0.07	0.06	0.23	0.22
Diluted net earnings per share (note 16)	\$ 0.07	\$ 0.06	\$ 0.23	\$ 0.22

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Net earnings	\$ 12,408	\$ 7,411	\$ 47,229	\$ 38,615
Other comprehensive income:				
Foreign currency translation adjustment, net of tax of \$Nil (2014 - \$164 and \$204) (note 20(b)(iii))	(19,239)	(42,014)	121,953	5,390
Change in fair value of cash flow hedge, net of tax of \$1,314 and \$6,409 (2014 - tax recovery of \$4,094 and \$8,772) (note 20(b)(ii))	2,960	(7,162)	9,404	(19,086)
Unrealized change in value of available-for-sale investments	46	(243)	(1)	(243)
Change in pension and other post-employment benefits, net of tax of \$3,343 and \$3,087 (2014 - tax recovery of \$210 and \$3) (note 8)	4,816	(47)	4,762	(497)
Other comprehensive income (loss), net of tax	(11,417)	(49,466)	136,118	(14,436)
Comprehensive income (loss)	991	(42,055)	183,347	24,179
Comprehensive income (loss) attributable to the non-controlling interests	(12,424)	(18,232)	8,399	(8,690)
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	\$ 13,415	\$ (23,823)	\$ 174,948	\$ 32,869

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statement of Equity

(thousands of Canadian dollars)
For the six months ended June 30, 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)	—	—	—	—	63,038	—	(15,809)	47,229
Redeemable non- controlling interests not included in equity	—	—	—	—	—	—	1,867	1,867
Other comprehensive income	—	—	—	—	—	111,910	24,208	136,118
Dividends declared and distributions to non-controlling interests	—	—	—	—	(51,034)	—	(1,115)	(52,149)
Dividends and issuance of shares under dividend reinvestment plan	12,345	—	—	—	(12,345)	—	—	—
Contributions received from non-controlling interests	—	—	—	—	—	—	10,815	10,815
Shares issued pursuant to public offering, net of costs	(307)	—	—	—	—	—	—	(307)
Issuance of common shares under share- based compensation plan	716	—	—	(282)	(60)	—	—	374
Share-based compensation	—	—	—	2,146	—	—	—	2,146
Balance, June 30, 2015	\$1,646,016	\$213,805	\$ 110,503	\$ 34,932	\$ (505,706)	\$ 146,123	\$336,808	\$1,982,481

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Statements of Cash Flows

(thousands of Canadian dollars)

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Cash provided by (used in):				
Operating Activities				
Net earnings from continuing operations	\$ 13,121	\$ 8,116	\$ 47,942	\$ 39,047
Adjustments and items not affecting cash:				
Depreciation of property, plant and equipment	34,344	24,819	67,400	51,714
Amortization of intangible assets	1,244	1,072	2,457	2,151
Other amortization	1,927	1,217	3,529	1,608
Deferred taxes	6,723	3,213	24,478	13,940
Unrealized loss (gain) on derivative financial instruments	(2,901)	851	(2,805)	3,964
Share-based compensation	1,022	491	1,914	832
Cost of equity funds used for construction purposes	(547)	(491)	(1,097)	(1,007)
Pension and post-employment expense	(566)	(640)	542	(876)
Deferred insurance proceeds and revenue amortization	123	—	(621)	—
Write-down of long-lived assets	159	293	525	991
Unrealized gain on disposal of VIE investment	—	—	220	—
Changes in non-cash operating items (note 19)	45,445	45,163	(51,817)	(13,040)
Changes in non-cash operating items from discontinued operations	—	702	—	509
Cash used in discontinued operations	(1,284)	(261)	(1,284)	(453)
	98,810	84,545	91,383	99,380
Financing Activities				
Cash dividends on common shares	(20,926)	(13,367)	(38,358)	(27,242)
Cash dividends on preferred shares	(2,600)	(2,953)	(5,200)	(4,303)
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	(502)	(519)	(1,115)	(3,486)
Issuance of common shares, net of costs	531	123	485	279
Issuance of preferred shares, net of costs	—	(259)	—	96,274
Increase in long-term liabilities	60,038	258,218	197,368	672,550
Decrease in long-term liabilities	(92,502)	(251,641)	(93,111)	(545,427)
Increase in other long-term liabilities	1,740	—	3,948	523
Decrease in other long-term liabilities	(420)	(49)	(2,082)	—
	(54,641)	(10,447)	72,772	198,144
Investing Activities				
Increase (decrease) in other assets	5,731	(1,592)	5,973	(2,996)
Distributions received in excess of equity income	(121)	(355)	(142)	(212)
Proceeds from sale of discontinued operations	—	20,826	—	20,826
Receipt of principal on notes receivable	290	79	2,820	156
Additions to property, plant and equipment	(36,445)	(102,478)	(81,846)	(179,376)
Acquisitions of long-term investments	(9,332)	(10,606)	(70,656)	(10,606)
Acquisitions of operating entities	(329)	(8,197)	(3,717)	(8,845)
Acquisition of non-controlling interest	—	—	—	(127,260)
	(40,206)	(102,323)	(147,568)	(308,313)
Effect of exchange rate differences on cash	(322)	(137)	424	322
Increase (decrease) in cash and cash equivalents	3,641	(28,362)	17,011	(10,467)
Cash and cash equivalents, beginning of the period	22,643	31,734	9,273	13,839
Cash and cash equivalents, end of the period	\$ 26,284	\$ 3,372	\$ 26,284	\$ 3,372
Supplemental disclosure of cash flow information:				
Cash paid during the year for interest expense	\$ 9,121	\$ 9,387	\$ 34,768	\$ 28,356
Cash paid during the year for income taxes	\$ 3,420	\$ 1,263	\$ 3,884	\$ 1,351
Non-cash financing and investing activities:				
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	\$ 6,130	\$ 4,357	\$ 13,061	\$ 8,181
Property, plant and equipment acquisitions in accruals as at balance sheet date	\$ 19,074	\$ 11,704	\$ 19,074	\$ 11,704

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 six months period ended June 30, 2015 was a reduction of depreciation expense of \$1,320 and \$916, respectively. There was no impact on net earnings per share. 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 2015-10, 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.

2. Recently issued accounting pronouncements**(a) Recently adopted accounting pronouncements (continued)**

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. The Company will continue to show issuance costs related to its revolving credit facilities and related instruments as deferred 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 2015-11, 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.

2. Recently issued accounting pronouncements (continued)

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

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.

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.

3. Business acquisitions and development projects (continued)

(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. Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in late 2015 or early 2016.

(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. \$57,708 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"). It is anticipated that approximately U.S. \$22,800 will be funded by the Tax Investor in the later half of 2015. 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 June 30, 2015 is U.S. \$8,992.

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".

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 June 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 \$65,630 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 \$82,407. 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 June 30, 2015 include unbilled revenue of \$18,580 (December 31, 2014 - \$52,880) from the Company's regulated utilities. Accounts receivable as of June 30, 2015 are presented net of allowance for doubtful accounts of \$9,333 (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 approval 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 are effective as of July 1, 2015 for service rendered on and after November 1, 2014.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three and six months ended June 30, 2015 and 2014

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

Regulatory assets and liabilities consist of the following:

	June 30, 2015	December 31, 2014
Regulatory assets		
Environmental costs	\$ 101,295	\$ 102,735
Pension and post-employment benefits	67,488	65,745
Storm costs	133	2,050
Commodity costs adjustment	8,229	41,502
Rate case costs	3,808	4,161
Vegetation management	3,061	3,260
Debt premium	4,882	4,658
Rate adjustment mechanism	12,042	6,207
Asset retirement obligation	1,852	1,682
Tax related	5,394	4,350
Other	10,881	11,964
Total regulatory assets	\$ 219,065	\$ 248,314
Less current regulatory assets	(26,925)	(61,645)
Non-current regulatory assets	\$ 192,140	\$ 186,669
Regulatory liabilities		
Cost of removal	\$ 85,348	\$ 78,013
Rate-base offset	23,762	23,427
Commodity costs adjustment	23,163	10,389
Depreciation adjustment mechanism	3,347	3,518
Other	6,714	6,409
Total regulatory liabilities	\$ 142,334	\$ 121,756
Less current regulatory liabilities	(33,963)	(20,590)
Non-current regulatory liabilities	\$ 108,371	\$ 101,166

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three and six months ended June 30, 2015 and 2014

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

Long-term investments consist of the following:

	June 30, 2015	December 31, 2014
Equity-method investees		
50% interest in Odell Wind Project	\$ 4,006	\$ 2,267
2.5% interest in Northeast Expansion LLC	2,158	1,063
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	1,512	1,512
50% interest in the Valley Power Partnership	1,217	1,253
Other	1,171	503
	\$ 10,064	\$ 6,598
Available-for-sale investment	\$ 1,426	\$ 137
Notes receivable		
Development loans (a)	\$ 88,088	\$ 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%	334	649
Silverleaf resorts loan, interest at 15.48% maturing July 2020	2,524	2,344
Other	1,178	782
	110,277	39,510
Total long-term investments	121,767	46,245
Less current portion	(334)	(2,966)
Non-current long-term investments	\$ 121,433	\$ 43,279

(a) Development loans

In 2014, the Company advanced U.S. \$13,159 to Odell SponsorCo for development costs associated with the Odell Wind Project (the "Project"). In 2015, the Company advanced an additional U.S. \$57,368 to the Project for a total advance of U.S. \$70,527. In 2015, the Company also issued a U.S. \$1,119 letter of credit on behalf of the Project pursuant to the generator interconnection agreement. The Project's third-party construction loan and tax equity investment is expected to close in the second half of 2015.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three and six months ended June 30, 2015 and 2014

*(in thousands of Canadian dollars, except as noted and per share amounts)***7. Long-term liabilities**

Long-term liabilities consist of the following:

	June 30, 2015	December 31, 2014
Generation Group		
\$350,000 Revolving unsecured credit facility	\$ 102,739	\$ 23,400
\$485,000 Algonquin Power Co.- Senior unsecured notes	481,722	481,438
\$35,459 Long Sault Hydro Facility - Senior debt	35,529	35,997
\$2,816 Chuteford Hydro Facility - Senior debt	2,810	3,022
U.S. \$76,000 Shady Oaks Wind Facility - Senior debt	—	88,168
Distribution Group		
U.S. \$200,000 Revolving unsecured credit facility	42,841	23,898
U.S. \$455,000 Liberty Utilities Co. - Senior unsecured notes	564,042	419,876
U.S. \$70,000 Calpeco Electric System - Senior unsecured notes	86,588	80,368
U.S. \$50,000 Liberty Water Co - Senior unsecured notes	61,748	57,301
U.S. \$19,500 New England Gas System - First mortgage bonds	29,246	27,288
U.S. \$15,000 Granite State Electric System - Senior unsecured notes	18,706	17,373
U.S. \$10,565 LPSCo Water System - IDA bonds	13,196	12,441
U.S. \$914 Bella Vista Water System - Loans	1,142	1,149
	\$ 1,440,309	\$ 1,271,719
Less current portion	(8,579)	(9,130)
	\$ 1,431,730	\$ 1,262,589

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 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.

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

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 June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Service cost	\$ 1,510	\$ 1,310	\$ 3,134	\$ 2,608
Interest cost	2,244	2,045	4,526	4,089
Expected return on plan assets	(2,885)	(2,479)	(5,726)	(4,958)
Amortization of net actuarial loss (gain)	302	(85)	600	(170)
Amortization of prior service costs	(131)	—	(163)	—
Amortization of net regulatory assets/liabilities	960	499	2,208	997
Net benefit cost	\$ 2,000	\$ 1,290	\$ 4,579	\$ 2,566

	OPEB			
	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Service cost	\$ 713	\$ 527	\$ 1,433	\$ 1,054
Interest cost	656	540	1,318	1,081
Expected return on plan assets	(188)	(157)	(377)	(315)
Amortization of net actuarial loss (gain)	33	(157)	65	(315)
Amortization of net regulatory assets/liabilities	215	43	508	86
Net benefit cost	\$ 1,429	\$ 796	\$ 2,947	\$ 1,591

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 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. \$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 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.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three and six months ended June 30, 2015 and 2014

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

Other long-term liabilities consist of the following:

	June 30, 2015	December 31, 2014
Advances in aid of construction	\$ 87,407	\$ 81,104
Environmental obligation	66,318	72,305
Deferred tax credit (note 15)	4,145	19,130
Deferred insurance proceeds	10,788	12,191
Asset retirement obligation	15,795	13,884
Other	34,407	30,157
	218,860	228,771
Less current portion	(42,202)	(49,303)
	\$ 176,658	\$ 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	1,396,905
Common shares, end of period	239,546,373

(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 six months ended June 30, 2015, 20,814 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 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 six months ended June 30, 2015, APUC recorded \$1,218 and \$2,089 (2014 - \$571 and \$992) in total share-based compensation expense. The compensation expense is recorded as part of administrative expenses in the unaudited interim consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As of June 30, 2015, total unrecognized compensation costs related to non-vested options and performance share unit were \$4,983 and \$3,144, respectively, and are expected to be recognized over a period of 2.06 years and 1.85, 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	97,745	11,326	(1)	4,457	113,527
Amounts reclassified	—	(1,922)	—	305	(1,617)
Net current period OCI (loss)	97,745	9,404	(1)	4,762	111,910
Balance, June 30, 2015	\$ 130,241	\$ 32,568	\$ —	\$ (16,686)	\$ 146,123

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 administrative 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 six months ended June 30, 2015, the Company declared dividends to shareholders on common shares totaling \$30,243 and \$58,050, respectively (2014 - \$17,634 and \$35,218).

The Board declared a dividend on the Company's common shares of U.S. \$0.09625 or \$0.1202 per share payable on July 15, 2015 to the shareholders of record on June 30, 2015.

For the three and six months ended June 30, 2015, the Company declared and paid dividends to Series A preferred shareholders totaling \$1,350 and \$2,700, respectively (2014 - \$1,350 and \$2,700) or \$0.2812 and \$0.5625, respectively, per Series A preferred share (2014 - \$0.2813 and \$0.5625 per Series A preferred share).

For the three and six months ended June 30, 2015, the Company declared and paid dividends to Series D preferred shareholders totaling \$1,250 and \$2,500, respectively (2014 - \$1,603 and \$1,603) or \$0.3125 and \$0.625, respectively, per Series D preferred share (2014 - \$0.4007 and \$0.4007 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 six months ended June 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. \$1,907 and U.S. \$3,544, respectively (2014 - U.S. \$2,174 and U.S. \$6,192). For the three and six months ended June 30, 2015, Liberty Utilities purchased natural gas amounting to U.S. \$1,216 and U.S. \$1,339, respectively (2014 - U.S. \$1,765 and U.S. \$4,742) 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 June 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 six months ended June 30, 2015, APUC reimbursed direct costs in connection with the use of the aircraft of \$208 and \$397 (2014 - \$83 and \$298).

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 six months ended June 30, 2015 were \$nil (2014 - \$89 and \$178).

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 six months ended June 30, 2015 APUC paid \$Nil and \$20 (2014 - \$28 and \$74) 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.

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 June 30,		Six months ended June 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	(8,009)	(7,485)	(16,871)	(15,975)
Other net earnings attributable to non-controlling interests	485	298	1,062	657
Total net loss attributable to non-controlling interests	\$ (7,524)	\$ (7,187)	\$ (15,809)	\$ (11,835)

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 six months ended June 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, recognition of deferred credits, inter-corporate dividends, and non-deductible expenses.

Included in deferred income tax expense (recovery) for the three and six months ended June 30, 2015 is \$283 and \$1,490 (2014 - \$1,257 and \$2,210) related to the recognition of deferred credits from the utilization of deferred income tax assets.

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 three and six months period ended June 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 six months ended June 30, 2015 are as follows:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Net earnings attributable to common shareholders of APUC	\$ 17,332	\$ 11,645	\$ 57,838	\$ 46,147
Discontinued operations	(713)	(705)	(713)	(432)
Net earnings attributable to common shareholders of APUC from continuing operations - Basic and Diluted	\$ 18,045	\$ 12,350	\$ 58,551	\$ 46,579
Weighted average number of shares and subscription receipts				
Basic	251,440,347	207,354,112	251,110,176	207,067,645
Effect of dilutive securities	3,513,568	1,659,542	4,076,387	1,778,967
Diluted	254,953,915	209,013,654	255,186,563	208,846,612

For the three and six months ended June 30, 2015, the shares potentially issuable as a result of 1,608,974 and 1,608,974 stock options (2014 – 1,786,401 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.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three and six months ended June 30, 2015 and 2014

*(in thousands of Canadian dollars, except as noted and per share amounts)***17. Segmented information (continued)**

	Three months ended June 30, 2015					
	Renewable	Generation Thermal	Total	Distribution	Corporate	Total
Revenue						
Regulated electricity distribution	\$ —	\$ —	\$ —	\$ 46,567	\$ —	\$ 46,567
Regulated gas distribution	—	—	—	71,012	—	71,012
Regulated water reclamation and distribution	—	—	—	19,172	—	19,172
Non-regulated energy sales	43,968	8,409	52,377	—	—	52,377
Other revenue	4,617	1,196	5,813	1,217	—	7,030
	48,585	9,605	58,190	137,968	—	196,158
Operating expenses	13,325	3,133	16,458	50,158	15	66,631
Regulated electricity purchased	—	—	—	25,201	—	25,201
Regulated gas purchased	—	—	—	20,289	—	20,289
Non-regulated energy purchased	836	3,116	3,952	—	—	3,952
	34,424	3,356	37,780	42,320	(15)	80,085
Administrative expenses	3,700	74	3,774	4,664	93	8,531
Depreciation of property, plant and equipment	13,988	1,671	15,659	17,496	1,189	34,344
Amortization of intangible assets	770	248	1,018	226	—	1,244
Other amortization	(20)	—	(20)	1,263	—	1,243
Gain on foreign exchange	—	—	—	—	(43)	(43)
Interest expense	6,817	256	7,073	9,106	348	16,527
Interest, dividend, equity-investment and other income	(16)	42	26	(1,048)	(508)	(1,530)
Other gains	(1,311)	—	(1,311)	—	—	(1,311)
Acquisition-related costs	—	—	—	—	459	459
Write-down of long-lived assets	390	8	398	(21)	—	377
Gain on derivative financial instruments	(1,880)	—	(1,880)	—	(480)	(2,360)
Earnings (loss) from continuing operations before income taxes	\$ 11,986	\$ 1,057	\$ 13,043	\$ 10,634	\$ (1,073)	\$ 22,604
Capital expenditures	\$ 8,089	\$ 375	\$ 8,464	\$ 26,802	\$ 1,179	\$ 36,445

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Notes to the Unaudited Interim Consolidated Financial Statements

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*(in thousands of Canadian dollars, except as noted and per share amounts)***17. Segmented information (continued)**

	Three months ended June 30, 2014					
	Generation			Distribution	Corporate	Total
	Renewable	Thermal	Total			
Revenue						
Regulated electricity distribution	\$ —	\$ —	\$ —	\$ 44,451	\$ —	\$ 44,451
Regulated gas distribution	—	—	—	71,263	—	71,263
Regulated water reclamation and distribution	—	—	—	16,381	—	16,381
Non-regulated energy sales	41,406	9,084	50,490	—	—	50,490
Other revenue	4,417	794	5,211	768	—	5,979
	45,823	9,878	55,701	132,863	—	188,564
Operating expenses	11,834	2,862	14,696	45,461	15	60,172
Regulated electricity purchased	—	—	—	24,725	—	24,725
Regulated gas purchased	—	—	—	33,009	—	33,009
Non-regulated energy purchased	1,966	3,839	5,805	—	—	5,805
	32,023	3,177	35,200	29,668	(15)	64,853
Administrative expenses	3,115	84	3,199	5,481	(434)	8,246
Depreciation of property, plant and equipment	12,141	1,449	13,590	10,522	707	24,819
Amortization of intangible assets	676	213	889	183	—	1,072
Other amortization	—	—	—	314	—	314
Loss on foreign exchange	—	—	—	—	825	825
Interest expense	8,496	597	9,093	5,773	1,289	16,155
Interest, dividend, equity-investment and other income	(389)	(161)	(550)	(968)	(842)	(2,360)
Acquisition-related costs	—	—	—	—	224	224
Write-down of long-lived assets	—	(4)	(4)	293	—	289
(Gain) loss on derivative financial instruments	1,957	—	1,957	—	(614)	1,343
Earnings (loss) from continuing operations before income taxes	6,027	999	7,026	8,070	(1,170)	13,926
Loss from discontinued operations before income taxes	332	366	698	—	—	698
Earnings (loss) before income taxes	\$ 5,695	\$ 633	\$ 6,328	\$ 8,070	\$ (1,170)	\$ 13,228
Capital expenditures	\$ 64,737	\$ 1,568	\$ 66,305	\$ 34,967	\$ 1,206	\$ 102,478

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Notes to the Unaudited Interim Consolidated Financial Statements

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

	Six months ended June 30, 2015					
	Renewable	Generation Thermal	Total	Distribution	Corporate	Total
Revenue						
Regulated electricity distribution	\$ —	\$ —	\$ —	\$ 116,156	\$ —	\$ 116,156
Regulated gas distribution	—	—	—	300,224	—	300,224
Regulated water reclamation and distribution	—	—	—	36,251	—	36,251
Non-regulated energy sales	91,202	18,887	110,089	—	—	110,089
Other revenue	9,620	2,133	11,753	3,539	—	15,292
	100,822	21,020	121,842	456,170	—	578,012
Operating expenses	25,911	5,654	31,565	106,196	30	137,791
Regulated electricity purchased	—	—	—	71,460	—	71,460
Regulated gas purchased	—	—	—	158,321	—	158,321
Non-regulated energy purchased	7,051	10,324	17,375	—	—	17,375
	67,860	5,042	72,902	120,193	(30)	193,065
Administrative expenses	7,980	180	8,160	10,573	245	18,978
Depreciation of property, plant and equipment	28,202	3,348	31,550	34,150	1,700	67,400
Amortization of intangible assets	1,539	498	2,037	420	—	2,457
Other amortization	(40)	—	(40)	3,401	—	3,361
Gain on foreign exchange	—	—	—	—	(1,286)	(1,286)
Interest expense	15,112	586	15,698	16,652	810	33,160
Interest, dividend, equity-investment and other income	(863)	(148)	(1,011)	(1,974)	(1,000)	(3,985)
Other gains	(2,409)	—	(2,409)	—	—	(2,409)
Acquisition-related costs	—	—	—	—	758	758
Write-down of long-lived assets	20	—	20	252	—	272
Gain on derivative financial instruments	(2,073)	—	(2,073)	—	(384)	(2,457)
Earnings (loss) from continuing operations before income taxes	\$ 20,392	\$ 578	\$ 20,970	\$ 56,719	\$ (873)	\$ 76,816
Property, plant and equipment	\$1,677,560	\$ 88,733	\$1,766,293	\$1,676,485	\$ 60,732	\$ 3,503,510
Equity-method investees	4,031	1,217	5,248	1,146	3,670	10,064
Total assets	1,993,923	110,287	2,104,210	2,191,987	100,306	4,396,503
Capital expenditures	28,263	599	28,862	50,342	2,642	81,846

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

17. Segmented information (continued)

	Six months ended June 30, 2014					
	Generation			Distribution	Corporate	Total
	Renewable	Thermal	Total			
Revenue						
Regulated electricity distribution	\$ —	\$ —	\$ —	\$ 101,712	\$ —	\$ 101,712
Regulated gas distribution	—	—	—	279,126	—	279,126
Regulated water reclamation and distribution	—	—	—	31,022	—	31,022
Non-regulated energy sales	84,987	23,423	108,410	—	—	108,410
Other revenue	7,418	1,559	8,977	1,451	—	10,428
	92,405	24,982	117,387	413,311	—	530,698
Operating expenses	23,010	5,178	28,188	88,795	30	117,013
Regulated electricity purchased	—	—	—	58,905	—	58,905
Regulated gas purchased	—	—	—	172,476	—	172,476
Non-regulated energy purchased	12,389	13,675	26,064	—	—	26,064
	57,006	6,129	63,135	93,135	(30)	156,240
Administrative expenses	6,418	169	6,587	9,440	(54)	15,973
Depreciation of property, plant and equipment	24,003	2,910	26,913	23,796	1,005	51,714
Amortization of intangible assets	1,339	442	1,781	370	—	2,151
Other amortization	—	—	—	664	—	664
Gain on foreign exchange	—	—	—	—	(931)	(931)
Interest expense	16,685	978	17,663	12,824	1,867	32,354
Interest, dividend, equity-investment and other income	(777)	22	(755)	(1,791)	(2,008)	(4,554)
Acquisition-related costs	—	—	—	—	497	497
Write-down of long-lived assets	—	372	372	293	—	665
(Gain) loss on derivative financial instruments	(141)	—	(141)	—	1,121	980
Earnings (loss) from continuing operations before income taxes	9,479	1,236	10,715	47,539	(1,527)	56,727
Loss from discontinued operations before income taxes	716	44	760	—	—	760
Earnings (loss) before income taxes	\$ 8,763	\$ 1,192	\$ 9,955	\$ 47,539	\$ (1,527)	\$ 55,967
Property, plant and equipment	\$1,602,465	\$ 85,000	\$1,687,465	\$1,531,166	\$ 59,791	\$3,278,422
Equity-method investees	2,267	1,253	3,520	1,563	1,515	6,598
Total assets	1,796,884	100,603	1,897,487	2,100,477	107,117	4,105,081
Capital expenditures	75,983	3,002	78,985	54,508	45,883	179,376

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 \$6,600. 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 June 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 \$7,900 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	\$ 63,352	\$ 51,134	\$ 54,214	\$ 58,616	\$ 61,499	\$116,890	\$ 405,705
Gas delivery, service and supply agreements	59,961	39,116	33,053	32,329	31,180	87,140	282,779
Service agreements	32,527	34,593	32,987	33,041	33,190	497,083	663,421
Capital projects	10,532	—	7,500	—	—	—	18,032
Operating leases	5,850	5,109	4,685	4,425	4,425	100,749	125,243
Total	\$172,222	\$129,952	\$132,439	\$128,411	\$130,294	\$801,862	\$1,495,180

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 June 30, 2015. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

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*(in thousands of Canadian dollars, except as noted and per share amounts)***18. Commitments and contingencies**

(c) Royalty payment

The loss from discontinued operations 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 June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Accounts receivable	\$ 89,298	\$ 66,630	\$ 34,243	\$ 22,181
Natural gas in storage	(7,438)	(13,285)	14,869	5,885
Supplies and consumable inventory	(1,236)	65	(1,794)	(710)
Income taxes receivable	(133)	10	(158)	(1)
Prepaid expenses	1,162	(2,050)	(8,418)	(2,120)
Accounts payable	(1,176)	22,031	(48,441)	21,711
Accrued liabilities	(39,744)	(20,239)	(83,099)	(30,551)
Current income tax liability	1,289	(1,467)	(371)	(360)
Net regulatory assets and liabilities	3,423	(6,532)	41,352	(29,075)
	\$ 45,445	\$ 45,163	\$ (51,817)	\$ (13,040)

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three and six months ended June 30, 2015 and 2014

*(in thousands of Canadian dollars, except as noted and per share amounts)***20. Financial instruments**

(a) Fair value of financial instruments

June 30, 2015	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	\$ 110,277	\$ 112,674	\$ —	\$ 112,674	\$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	62,960	62,960	—	—	62,960
Energy contracts not designated as a cash flow hedge	5	5	—	—	5
Commodity contracts for regulated operations	7	7	—	7	—
Total derivative financial instruments	62,972	62,972	—	7	62,965
Total financial assets	\$ 173,249	\$ 175,646	\$ —	\$ 112,681	\$ 62,965
Long-term liabilities	\$ 1,440,309	\$ 1,509,805	\$ 522,629	\$ 987,176	\$ —
Preferred shares, Series C	18,607	18,576	—	18,576	—
Derivative financial instruments:					
Energy contracts not designated as a cash flow hedge	35	35	—	—	35
Cross-currency swap designated as a net investment hedge	55,638	55,638	—	55,638	—
Interest rate swap designated as a hedge	4,247	4,247	—	4,247	—
Interest rate swaps not designated as a hedge	512	512	—	512	—
Commodity contracts for regulated operations	1,468	1,468	—	1,468	—
Total derivative financial instruments	61,900	61,900	—	61,865	35
Total financial liabilities	\$ 1,520,816	\$ 1,590,281	\$ 522,629	\$ 1,067,617	\$ 35

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three and six months ended June 30, 2015 and 2014

*(in thousands of Canadian dollars, except as noted and per share amounts)***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 June 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 \$22.02 to \$111.46 with a weighted average of \$39.17 as of June 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 six months ended June 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	1,347,609
Gas options	397,818
	1,745,427

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:

	June 30, 2015	December 31, 2014
Regulatory assets:		
Gas swap contracts	U.S. \$ 1,087	U.S. \$ 2,178
Gas option contracts	U.S. \$ 88	U.S. \$ 346
Regulatory liabilities:		
Gas swap contracts	U.S. \$ 5	U.S. \$ —

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities 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)
76,766	December 2016	\$ 68.13	AESO
850,833	December 2022	U.S. \$ 42.81	PJM Western HUB
3,636,531	December 2022	U.S. \$ 30.25	NI HUB
4,136,096	December 2027	U.S. \$ 36.46	ERCOT North HUB

As of June 30, 2015, an amount receivable under the derivatives for Sandy Ridge, Senate and Minonk Wind Facilities of \$1,906 (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 gain of \$5,046 and \$437 for the three and six months ended June 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 June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Effective portion of cash flow hedge, gain (loss)	\$ 4,488	\$(11,071)	\$ 11,326	\$(27,098)
Amortization on cash flow hedge	(8)	(7)	(17)	(15)
Gain (loss) reclassified from AOCI into non-regulated energy sales	(1,520)	3,916	(1,905)	8,027
	\$ 2,960	\$ (7,162)	\$ 9,404	\$(19,086)
Less non-controlling interest	—	—	—	5,982
Change in OCI attributable to shareholders of APUC	\$ 2,960	\$ (7,162)	\$ 9,404	\$(13,104)

The Company expects \$9,582 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 six months ended June 30, 2015 (2014 - gain of \$114 and loss of \$1,014) 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 gain of \$8,790 and a loss \$20,496 (2014 - gain of \$13,495 and \$3,525) was recorded in OCI for the three months and six months ended June 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 through the use of short-term financial forward energy purchase contracts which are classified as derivative instruments. The electricity derivative contracts are net settled fixed-for-floating swaps whereby APUC pays a fixed price and receives the floating or indexed price on a notional quantity of energy over the remainder of the contract term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

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 is party to an interest rate swap whereby, the Company pays a fixed interest rate of 4.47% on a notional amount of \$59,373 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. As of June 30, 2015, the estimated fair value of the interest rate swap was a liability of \$512 (December 31, 2014 – liability of \$1,383). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

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 June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Change in unrealized loss (gain) on derivative financial instruments:				
Interest rate swaps	\$ (515)	\$ (452)	\$ (872)	\$ (842)
Energy derivative contracts	35	(279)	488	1,881
Total change in unrealized loss (gain) on derivative financial instruments	\$ (480)	\$ (731)	\$ (384)	\$ 1,039
Realized loss (gain) on derivative financial instruments:				
Interest rate swaps	514	492	983	982
Energy derivative contracts	12	—	(635)	(3,966)
Total realized loss (gain) on derivative financial instruments	\$ 526	\$ 492	\$ 348	\$ (2,984)
Loss (gain) on derivative financial instruments not accounted for as hedges	46	(239)	(36)	(1,945)
Ineffective portion of derivative financial instruments accounted for as hedges	(2,406)	1,582	(2,421)	2,925
Loss (gain) on derivative financial instruments	\$ (2,360)	\$ 1,343	\$ (2,457)	\$ 980

21. Comparative figures

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

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Christopher Huskilson – President & Chief Executive Officer, Emera Inc.

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

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