Algonquin Power & Utilities Corp.

ALGONQUIN
Power & Utilities Corp.

MANAGEMENT'S DISCUSSION & ANALYSIS

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

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and nine months ended September 30, 2014. The Management's Discussion & Analysis ("MD&A") should be read in conjunction with APUC's interim unaudited consolidated financial statements for the three and nine months ended September 30, 2014 and 2013 as well as its audited consolidated financial statements for the years ended December 31, 2013 and 2012. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of November 13, 2014.

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 adjusted net earnings", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy 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 adjusted net earnings", "per share cash provided by adjusted funds from operations", Adjusted EBITDA, "net energy 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 adjusted net earnings", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy 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 adjusted net earnings", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy 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 metric 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, unrealized gains or losses on derivative financial instruments, non-cash write downs of intangibles and property, plant and equipment, earnings attributable to non-controlling interests, gains or losses on foreign exchange, earnings or loss from discontinued operations and other infrequent items unrelated to normal ongoing operations. APUC adjusts for these factors as they are typically 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 metric 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, unrealized gains or losses on derivative financial instruments and interest rate swaps, acquisition costs, litigation expenses, non-cash write downs of intangibles and property, plant and equipment, earnings or loss from discontinued operations and other infrequent items unrelated to normal operations 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 metric 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 infrequent items unrelated to normal operations 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 sales is a non-GAAP metric 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 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 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 metric 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 is a diversified electric generation, distribution and transmission utility which strives to 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. $0.0875 per share or U.S. $0.35 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. 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 conducts its utility business through two subsidiaries: Algonquin Power Co. ("APCo"), which owns and operates a diversified portfolio of electric generation assets; and Liberty Utilities Co. ("Liberty Utilities"), which owns and operates North American electric, natural gas, water/wastewater utility transmission and distribution systems.

Generation: Algonquin Power Co.

APCo 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. APCo seeks to deliver continuing growth through development of new Greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

APCo owns or has interests in: hydroelectric facilities with a combined generating capacity of approximately 120 MW, wind powered generating stations with a combined generating capacity of 650 MW, and a solar energy facility with approximately 10 MW of installed generating capacity. 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.

APCo owns or has interests in thermal energy facilities with approximately 350 MW of installed generating capacity. Approximately 93% of the electrical output from the owned thermal facilities is sold pursuant to long term power purchase agreements ("PPA") with major utilities and which have a weighted average remaining contract life of 6 years.

APCo also has a portfolio of development projects that, between 2014 and 2016, will add approximately 523 MW of generation capacity from wind powered generating stations and approximately 20 MW from photovoltaic solar powered generation stations with an average contract life of 22 years.

Distribution and Transmission: Liberty Utilities Co.

Liberty Utilities is a diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection distribution and transmission utility services to approximately 488,100 connections. Liberty Utilities 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 material organic investment opportunities within its service territories, Liberty Utilities delivers continued growth in earnings through accretive acquisition of additional utility systems and other rate regulated assets.

The utility systems owned by Liberty Utilities operate under rate regulation, generally overseen by the public utility commissions of the states in which they operate. Liberty Utilities reports the performance of its utility operations through three regions – West, Central, and East.

The Liberty Utilities (West) region is comprised of regulated electrical and water distribution and wastewater collection utility systems. The regulated electrical distribution utility and related generation assets (the "CalPeco Electric System") serve approximately 48,300 electric connections in the State of California. Liberty Utilities (West) region's regulated water and wastewater utility systems serve approximately 69,400 water and wastewater connections located in the State of Arizona.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems. The regulated natural gas utilities serve approximately 86,000 natural gas connections located in the States of Missouri, Illinois, and Iowa. Liberty Utilities (Central) region's regulated water distribution and wastewater collection utilities serve approximately 33,700 water and wastewater customers located in the States of Arkansas, Illinois, Missouri, and Texas.

Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems located in the State of New Hampshire, and regulated natural gas distribution utility systems located in the States of Georgia and Massachusetts. Liberty Utilities provides regulated local electrical utility services to approximately 44,600 electric connections in the State of New Hampshire; and regulated local gas distribution utility services to approximately 206,100 natural gas connections located in the States of Georgia, New Hampshire and Massachusetts.

MAJOR THIRD QUARTER HIGHLIGHTS

Corporate

Strengthened Balance Sheet

Issuance of Common Shares

On September 16, 2014, APUC completed a public offering (the "Offering") of 16,860,000 common shares at a price of $8.90 per share, for gross proceeds of approximately $150.0 million. On September 26, 2014, the underwriters exercised the over-allotment option granted with the Offering and an additional 2,529,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued 19,389,000 common shares under the Offering for the total gross proceeds of approximately $172.6 million.

Net proceeds of the Offering will be used to finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities, and for general corporate purposes.

Private Placement of Subscription Receipts to Emera Inc.

On September 4, 2014, APUC and Emera Inc. (“Emera”) entered into a subscription agreement pursuant to which Emera agreed to subscribe for an aggregate of 7,865,170 subscription receipts (“Subscription Receipts”) of APUC at a price of $8.90 per Subscription Receipt, for a subscription price of $70.0 million.

On September 26, 2014, as a result of the Underwriters exercising the Over-Allotment Option, an additional 843,000 Subscription Receipts were issued to Emera at a price of $8.90 per Subscription Receipt, for an aggregate subscription price of $77.5 million.

The proceeds of the Subscription Receipt private placement are intended to be used to partially finance the Odell Wind Project (described below).

Dividend Increased to U.S. $0.35 Per Common Share Annually

On August 14, 2014, the Board approved a dividend increase to U.S. $0.35, paid quarterly at a rate of U.S. $0.0875. Based on the U.S. dollar exchange rate as at August 14, 2014 of $1.091, the change in dividend to U.S. $0.35 represents an equivalent dividend of CDN $0.382 and an increase of 12.4% as compared to the previous dividend of CDN $0.34.

The change in the currency of the dividend better aligns APUC's dividend with the currency profile of its underlying operations. APUC's combined assets of Algonquin Power Co. and Liberty Utilities Co. are approximately 80% based in the U.S., which generate approximately 80% of its underlying cash flows.

Management believes that the dividend increase is consistent with APUC’s stated strategy of delivering total shareholder return comprised of attractive current dividend yield and capital appreciation founded on increased earnings and cash flows.

Generation: Algonquin Power Co.

Acquisition of Odell Wind Project

On September 4, 2014, APCo announced an opportunity to acquire an interest in the Odell Wind Farm LLC (“Odell”), which owns a 200 MW construction-stage wind development project (“Odell Wind Project”) in the state of Minnesota. APCo is continuing its engineering, regulatory and financial analysis in respect of the Odell Wind Project to ensure that it meets all of APCo’s requirements for an approved development project.

The Odell Wind Project is located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota and is being constructed on approximately 23,000 acres of leased land. The project will utilize 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year power purchase agreement, all energy, capacity and renewable energy credits from the Odell Wind Project will be sold to Northern States Power Company, a subsidiary of Xcel Energy Inc., which is a diversified utility operating in the midwest U.S. The total construction costs of the Odell Wind Project are estimated to be U.S. $322.8 million. It is anticipated that the Odell Project will qualify for U.S. federal production tax credits having satisfied the Internal Revenue Service 5% beginning of construction investment safe-harbor guidance. Accordingly, approximately 60% of the permanent project financing is expected to be funded by tax equity investors. APCo’s share of the balance will be financed through a private placement of subscription receipts to Emera Inc. and long term debt.

APCo Credit Facility

On July 31, 2014, APCo increased the credit available under the senior unsecured credit facility ("APCo Facility") to $350 million from $200 million. The larger facility will be used to provide additional liquidity in support of APCo's $1,243 million portfolio of development projects to be completed over the next three years. In addition to the larger size, the maturity of the facility has been extended from three to four years and now extends until July 31, 2018.

Distribution and Transmission: Liberty Utilities Co.

Agreement to acquire Park Water System

On September 19, 2014, Liberty Utilities announced the entering into an agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure, 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.

Total consideration for the utility purchase is expected to be approximately U.S. $327 million, which includes the assumption of approximately U.S. $77 million of existing long-term utility debt. The acquisition will maintain APUC's strategic business mix and further enhance its investment grade consolidated capital structure.

2014 NINE MONTH RESULTS FROM OPERATIONS

Key Selected Nine month Financial Information

	Nine months ended September 30,	
(millions of dollars except per share information)	**2014**	**2013**
Revenue	**$ 684.2**	$ 470.0
Adjusted EBITDA[1]	**206.2**	159.6
Cash provided by operating activities	**96.3**	70.5
Adjusted funds from operations[1]	**140.6**	107.1
Net earnings attributable to Shareholders from continuing operations	**44.8**	42.4
Net earnings attributable to Shareholders	**44.1**	7.1
Adjusted net earnings[1]	**53.2**	40.6
Dividends declared to Common Shareholders	**57.5**	50.8
Weighted Average number of common shares outstanding	**208,322,421**	203,721,023
Per share		
Basic net earnings from continuing operations	**$ 0.18**	$ 0.19
Basic net earnings	**$ 0.18**	$ 0.02
Adjusted net earnings[1,2]	**$ 0.22**	$ 0.18
Diluted net earnings	**$ 0.18**	$ 0.02
Cash provided by operating activities[2]	**$ 0.46**	$ 0.35
Adjusted funds from operations[1,2]	**$ 0.64**	$ 0.51
Dividends declared to Common Shareholders	**$ 0.27**	$ 0.25
Total Assets	**3,808.5**	3,156.4
Total Liabilities[3]	**1,413.5**	1,092.0

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

For the nine months ended September 30, 2014, APUC experienced an average U.S. exchange rate for the quarter of approximately 1.0944, as compared to 1.0234 in the same period in 2013. 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 nine months ended September 30, 2014, APUC reported total revenue of $684.2 million as compared to $470 million during the same period in 2013, an increase of $214.2 million. The major factors resulting in the increase in APUC revenue for the nine months ended September 30, 2014, as compared to the corresponding period in 2013, are set out as follows:

	Nine months ended September 30, 2014 (millions)	
Comparative Prior Period Revenue	$	470.0
Significant Changes:		
Liberty Utilities:		
Central – Revenue increase due to the increased customer demand in the Midstates Gas Systems, and water and waste water systems		8.6
East – Revenue increase at the Granite State Electric System and EnergyNorth Gas System due to higher customer demand		33.0
East – Revenue increase due to higher electricity rates at the Granite State Electric System (U.S. $10.2 million) and Peach State Gas System (U.S. $3.3 million)		13.4
East - Increased revenue due to acquisition of the Peach State Gas System (U.S. $28.9 million), and the New England Gas System (U.S. $67.8 million)		96.7
APCo:		
Renewable		
Higher overall wind resources net of hedge settlements at the Minonk, Senate, and Sandy Ridge Wind Facilities		(0.1)
Higher realized prices from Renewable Energy Credits generated from the U.S. Wind Facilities		4.6
Start of commercial operations for the Cornwall Solar Facility		4.7
Effect of hydrology resource compared to comparable period in prior year		(1.9)
Increased customer load at AES		2.8
Thermal		
Increased average prices at the Windsor Locks and Sanger Thermal Facilities		5.2
Impact of the stronger U.S. dollar		47.2
Current Period Revenue	$	684.2

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

Adjusted EBITDA for the nine months ended September 30, 2014 totalled $206.2 million, as compared to $159.6 million during the same period in 2013, an increase of $46.6 million or 29.2%. The increase in Adjusted EBITDA was primarily due to utility acquisitions completed in 2013, the impact of rate case settlements, and a stronger U.S. dollar. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the nine months ended September 30, 2014, net earnings attributable to Shareholders from continued operations totalled $44.8 million, as compared to $42.4 million during the same period in 2013, an increase of $2.4 million or 5.7%. The increase was due to $43.5 million in increased earnings from operating facilities, $1.0 million in increased foreign exchange gains, $0.5 million in increased interest and dividend income, $0.4 million due to a gain on sale of assets, $0.6 million in decreased acquisition related costs, and $6.5 million in decreased allocations to non controlling interests. These items were partially offset by: $15.9 million in increased depreciation and amortization expense, $5.8 million in increased administrative charges, $9.3 million in increased interest expense, $8.2 million in increased write-down of notes receivable and property plant and equipment, $1.8 million in decreased gains from derivative instruments, and $9.1 million in increased income tax expense (tax explanations are discussed in APUC: Corporate and Other Expenses), as compared to the same period in 2013.

For the nine months ended September 30, 2014, net earnings (including discontinued operations) attributable to Shareholders totalled $44.1 million, as compared to net earnings attributable to Shareholders of $7.1 million during the same period in 2013, an increase of $37.0 million. Net earnings per share totalled $0.18 for the nine months ended September 30, 2014, as compared to net earnings per share of $0.02 during the same period in 2013.

During the nine months ended September 30, 2014, cash provided by operating activities totalled $96.3 million or $0.46 per share, as compared to cash provided by operating activities of $70.5 million or $0.35 per share during the same period in 2013. During the nine months ended September 30, 2014, adjusted funds from operations totalled $140.6 million or $0.64 per share, as compared to adjusted funds from operations of $107.1 million or $0.51 per share during the same period in 2013. The change in adjusted funds from operations in the nine months ended September 30, 2014 is primarily due to increased earnings from operations, as compared to the same period in 2013.

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.

2014 THIRD QUARTER RESULTS FROM OPERATIONS

Key Selected Third Quarter Financial Information

	Three months ended September 30,	
(millions of dollars except per share information)	2014	2013
Revenue	**$ 151.9**	$ 127.9
Adjusted EBITDA[1]	**41.4**	40.2
Cash (used)/provided by operating activities	**(3.1)**	14.9
Adjusted funds from operations[1]	**18.7**	22.5
Net (loss)/earnings attributable to Shareholders from continuing operations	**(6.1)**	6.3
Net (loss)/earnings attributable to Shareholders	**(6.3)**	6.0
Adjusted net (loss)/earnings[1]	**(0.4)**	6.2
Dividends declared to Common Shareholders	**22.3**	17.5
Weighted Average number of common shares outstanding	**210,791,056**	205,527,475
Per share		
Basic net (loss)/earnings from continuing operations	**$ (0.04)**	$ 0.02
Basic net (loss)/earnings	**$ (0.04)**	$ 0.02
Adjusted net (loss)/earnings[1,2]	**$ (0.01)**	$ 0.02
Diluted net (loss)/earnings	**$ (0.04)**	$ 0.02
Cash (used)/provided by operating activities[2]	**$ (0.01)**	$ 0.07
Adjusted funds from operations[1,2]	**$ 0.08**	$ 0.10
Dividends declared to Common Shareholders	**$ 0.10**	$ 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.

For the three months ended September 30, 2014, APUC experienced an average U.S. exchange rate for the quarter of approximately 1.0892, as compared to 1.0382 in the same period in 2013. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the three months ended September 30, 2014 , APUC reported total revenue of $151.9 million, as compared to $127.9 million during the same period in 2013, an increase of $24.0 million. The major factors resulting in the increase in APUC revenue in the three months ended September 30, 2014, as compared to the corresponding period in 2013, are set out as follows:

		Three months ended September 30, 2014 (millions)
Comparative Prior Period Revenue	$	127.9
Significant Changes:		
Liberty Utilities:		
Revenue decrease primarily due to the lower customer demand in the EnergyNorth Gas, and Midstates Gas Systems		(1.4)
East – Revenue increase due to higher electricity rates as a result of the Granite State Electric System's rate case (U.S. 3.0 million), and the Peach State Gas System's GRAM filing (U.S. $1.2 million)		4.2
East - Increased revenue due to acquisition of the Peach State and New England Gas Systems		11.8
APCo:		
Renewable		
Decreased overall wind resources net of hedge settlements at most U.S. Wind Facilities		(0.4)
Start of commercial operations for the Cornwall Solar Facility		2.4
Effect of hydrology resource compared to comparable period in prior year		(1.3)
Thermal		
Increased average prices at the Sanger Thermal Facility		0.8
Impact of the stronger U.S. dollar		6.9
Other		1.0
Current Period Revenue	$	151.9

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

Adjusted EBITDA for the three months ended September 30, 2014 totalled $41.4 million, as compared to $40.2 million during the same period in 2013, an increase of $1.2 million or 3.0%. The increase in Adjusted EBITDA was primarily due to operations from the new Cornwall Solar Facility, increased wind resources at the St. Leon Wind Facilities, and a stronger U.S. dollar. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended September 30, 2014, net losses attributable to Shareholders from continued operations totalled $6.1 million, as compared to net earnings of $6.3 million during the same period in 2013, a decrease of $12.4 million. The decrease was due to $6.9 million in increased depreciation and amortization expense, $2.0 million in increased administration charges, $2.0 million in increased interest expense, and $7.2 million in increased write-down of notes receivable and property plant and equipment, as compared to the same period in 2013. These items were partially offset by $1.4 million in increased earnings from operations, $0.3 million in increased interest and dividends, $1.4 million in increased foreign exchange gains,

$0.1 million in decreased losses on sale of assets, $1.0 million in increased gains from derivative instruments, $0.1 million in decreased allocations of earnings to non-controlling interests, and $1.3 million in increased income tax recovery (tax explanations are discussed in *APUC: Corporate and Other Expenses),* as compared to the same period in 2013.

For the three months ended September 30, 2014, net losses (including discontinued operations) attributable to Shareholders totalled $6.3 million, as compared to net earnings attributable to Shareholders of $6.0 million during the same period in 2013, a decrease of $12.3 million. Net loss per share totalled $0.04 for the three months ended September 30, 2014, as compared to net earnings per share of $0.02 during the same period in 2013.

During the three months ended September 30, 2014, cash used by operating activities totalled a loss of $3.1 million or a loss of $0.01 per share, as compared to cash provided by operating activities of $14.9 million or $0.07 per share during the same period in 2013. During the three months ended September 30, 2014, adjusted funds from operations totalled $18.7 million or $0.08 per share, as compared to adjusted funds from operations of $22.5 million or $0.10 per share during the same period in 2013. The change in adjusted funds from operations in the three months ended September 30, 2014 is primarily due to decreased earnings from operations, as compared to the same period in 2013.

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.

GENERATION: ALGONQUIN POWER CO.

APCo: Renewable Energy Division

	Long Term Average Resource	Three months ended September 30 2014	Three months ended September 30 2013	Long Term Average Resource	Nine months ended September 30 2014	Nine months ended September 30 2013
Performance (GW-hrs sold)						
Hydro Facilities:						
Ontario Region[1]	**31.7**	**33.6**	26.7	**106.0**	**105.8**	51.1
Quebec Region	**62.3**	**57.5**	58.1	**202.1**	**187.1**	209.6
Maritime Region	**24.1**	**22.0**	55.3	**132.0**	**109.4**	165.2
Western Region	**23.8**	**27.0**	25.2	**52.4**	**60.8**	54.5
	141.9	**140.1**	165.3	**492.5**	**463.1**	480.4
Wind Facilities:						
Manitoba Region	**85.6**	**82.6**	71.6	**306.5**	**321.5**	281.5
Saskatchewan Region[2]	**19.9**	**16.0**	15.0	**63.9**	**63.9**	56.3
Pennsylvania Region[3]	**29.9**	**22.5**	20.0	**114.7**	**102.3**	100.1
Illinois Region[4]	**160.8**	**112.0**	141.3	**728.0**	**677.5**	667.3
Texas Region[5]	**91.7**	**92.8**	90.4	**380.4**	**398.6**	390.7
	387.9	**325.9**	338.3	**1,593.5**	**1,563.8**	1,495.9
Solar Facilities:						
Ontario Region[6]	**4.6**	**5.2**	—	**9.6**	**11.0**	—
Total	**534.4**	**471.2**	503.6	**2,095.6**	**2,037.9**	1,976.3

	Three months ended September 30 2014	Three months ended September 30 2013	Nine months ended September 30 2014	Nine months ended September 30 2013
Revenue	(millions)	(millions)	(millions)	(millions)
Energy sales	**$ 29.9**	$ 28.6	**$ 114.9**	$ 105.3
Less:				
Cost of Sales – Energy[7]	**(2.8)**	(1.6)	**(15.1)**	(4.9)
Realized gain/(loss) on AES hedges[8]	**(0.2)**	(0.5)	**3.8**	0.2
Net Energy Sales	**$ 26.9**	$ 26.5	**$ 103.6**	$ 100.6
Renewable Energy Credits ("REC")	**1.3**	1.2	**7.8**	3.5
Other Revenue	**0.2**	0.6	**1.1**	1.0
Total Net Revenue	**$ 28.4**	$ 28.3	**$ 112.5**	$ 105.1
Expenses				
Operating expenses	**(12.1)**	(10.5)	**(35.1)**	(29.0)
Interest and Other income	**0.5**	0.4	**1.3**	1.4
HLBV income/(loss)	**2.3**	1.0	**18.3**	13.5
Division operating profit	**$ 19.1**	$ 19.2	**$ 97.0**	$ 91.0

1 APCo's Long Sault hydro facility was offline during most of the first nine months of 2013 but with lost revenue covered by insurance. See below for additional commentary.

2 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.

3 Represents the operations of the Sandy Ridge Wind Facility.

4 Represents the operations of the Minonk and the Shady Oaks Wind Facilities. Production at the Shady Oaks was 46.2 GW-hrs and 247.7 GW-hrs in the 3 and 9 months ended September 30, 2014. Production at Shady Oaks can be subject to congestion related curtailment by the independent system operator but in this case compensation is expected to be received for lost energy sales.

5 Represents the operations of the Senate Wind Facility.

6 Represents the operations of Cornwall Solar, which commenced March 27, 2014.

7 Cost of Sales - Energy consists of energy purchases by Algonquin Energy Services ("AES"), which is resold to its retail and industrial customers. Under GAAP, in APUC's unaudited interim consolidated Financial Statements, these amounts are included in operating expenses.

8 See Financial statements note 20(b)(iv).

2014 Nine Month Operating Results

For the nine months ended September 30, 2014, the Renewable Energy Division produced 2,037.9 GW-hrs of electricity, as compared to 1,976.3 GW-hrs produced in the same period in 2013, an increase of 3.1%. The increased generation is largely attributable to APCo's Long Sault Hydro Facility being partly offline during the first nine months of 2013, with lost revenue covered by insurance, in addition to stronger wind resources in the Manitoba, Saskatchewan and Illinois regions, and production at the new Cornwall Solar Facility, which came online in 2014. The increased production in the Renewable Energy Division was largely offset by lower production from hydro facilities in Quebec and Maritime regions as compared to the same period in 2013. This level of production represents sufficient renewable energy to supply the equivalent of 150,933 homes on an annualized basis with renewable power. As a result of renewable energy production, the equivalent of 1,120,845 tons of CO_2 gas was prevented from entering the atmosphere in the nine months ended September 30, 2014.

During the nine months ended September 30, 2014, the Renewable Energy Division generated electricity equal to 97.2% of long-term projected average resources (wind, hydrology and solar), as compared to 94.3% during the same period in 2013. During the nine months ended September 30, 2014, the Manitoba Wind, Texas Wind and Western Hydro regions produced 5% to 16% above long-term average resources, while Saskatchewan Wind and Ontario Hydro regions achieved production approximately at long-term averages. Pennsylvania Wind, Maritime Wind, Illinois Wind and Quebec Hydro regions produced 7% to 17% lower than long-term average resources.

During the nine months ended September 30, 2014, APCo's solar facility located in Ontario had its second full quarter of operations generating 11.0 GW-hrs of electricity, which is equal to 13.0% above long-term average resources from the commercial operation date. The facility reached commercial operation on March 27, 2014 and has a 20 year FIT Power Purchase Agreement with the Ontario Power Authority.

For the nine months ended September 30, 2014, revenue from energy sales in the Renewable Energy Division totalled $114.9 million, as compared to $105.3 million during the same period in 2013, an increase of $9.6 million. As the purchase of energy by AES is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's sales results. For the nine months ended September 30, 2014, net energy sales in the Renewable Energy Division totalled $103.6 million, as compared to $100.6 million in the same period in 2013.

Revenue from generation at APCo's hydro facilities located in the Ontario, Quebec and Western regions decreased by $1.9 million, as compared to the same period in 2013 (including business interruption insurance proceeds for the Long Sault Hydro Facility). The decrease is attributed to lower hydrology in the Quebec region, primarily due to the Donnacona facility being offline and lower weighted average energy rates. Revenue from APCo's hydro facility located in the Maritime region decreased $0.4 million, primarily due to lower hydrology, which resulted in significantly lower sales to AES and thereby increased weighted average pricing.

Revenue from APCo's wind facilities located in the Manitoba region increased by $2.9 million due to higher wind resources at the St. Leon Wind facilities. Revenues from APCo's U.S. wind facilities located in Illinois, Pennsylvania and Texas regions increased by $6.1 million, primarily as a result of increased production due to a higher wind resource and a more favorable exchange rate compared to the same period last year. These gains were offset by hedge settlements under the Minonk, Senate and Sandy Ridge power hedges and a high spot power price caused by the unusually cold weather early in the year.

Revenue from generation at APCo's new solar facility located in Cornwall, Ontario totalled $4.7 million for the period. The facility achieved commercial operation on March 27, 2014 and therefore there is no comparative data from the previous year.

For the nine months ended September 30, 2014, revenue at AES increased $4.1 million or 31%, primarily due to increased customer load served. Revenue at AES primarily consists of wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine, merchant sales of production in excess of committed customer deliveries from the Tinker Facility and other revenue.

For the nine months ended September 30, 2014, energy purchase costs by AES totalled $15.1 million, as compared to $4.9 million during the same period in 2013, an increase of $10.2 million. AES' increased energy purchase costs for the nine months ended September 30, 2014 were primarily due to lower hydrology in the Maritime region, which required increased energy purchases from external suppliers at higher average prices. During this period, AES purchased approximately 143.4 GW-hrs of energy at market and fixed rates averaging U.S. $97 per MW-hr. During the nine months ended September 30, 2014, the Maritime region generated approximately 39% of the load required to service its customers as well as AES' customers, as compared to 75% in the same period in 2013. To mitigate the risk of higher average energy prices, AES had previously entered into certain power hedges as part of its risk mitigation strategies. For the nine months ended September 30, 2014, $3.8 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.

For the nine months ended September 30, 2014, REC revenue totalled $7.8 million, as compared to $3.5 million in the same period in 2013, an increase of $4.3 million primarily attributed to increased market pricing in the Illinois and Pennsylvania regions. 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 nine months ended September 30, 2014, REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities.

The Red Lily I Wind Facility located in Saskatchewan produced 63.9 GW-hrs of electricity for the nine months ended September 30, 2014. APCo's economic return from its investment in Red Lily 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, APCo has the right to exchange these contractual and debt interests in the Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the nine months ended September 30, 2014, APCo earned fees of $1.0 million (which is classified as other revenue) and interest income of $1.2 million from Red Lily I Wind Facility.

For the nine months ended September 30, 2014, operating expenses excluding energy purchases totalled $35.1 million, as compared to $29.0 million during the same period in 2013, an increase of $6.1 million. The increase was primarily attributable to the appreciation of the U.S. dollar, increased development costs, and cost of RECs contracted in the first quarter of 2014 but produced in the fourth quarter of 2013.

For the nine months ended September 30, 2014, interest and other income totalled $1.3 million, consistent with the same period in 2013. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility. This amount is included as part of APCo's earnings from its investment in Red Lily I Wind Facility, as discussed above.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of net tax attributes, primarily related to electricity production generated by APCo in the period from certain of its U.S. wind power generation facilities. The value of net tax attributes generated in the nine month period ended September 30, 2014 amounted to an approximate HLBV income of $18.3 million, as compared to $13.5 million in the prior year, primarily resulting from a stronger US dollar exchange rate, increased overall production, and a higher income allocation to APCo due to the reduced economic interest in the projects attributable to tax equity.

For the nine months ended September 30, 2014, the Renewable Energy Division's operating profit totalled $97.0 million, as compared to $91.0 million during the same period in 2013, an increase of $6.0 million. As a result of the stronger U.S. dollar, operating profit increased by $3.9 million.

2014 Third Quarter Operating Results

For the quarter ended September 30, 2014, the Renewable Energy Division produced 471.2 GW-hrs of electricity, as compared to 503.6 GW-hrs produced in the same period in 2013, a decrease of 6.4%. The decrease in generation is primarily due to lower wind resource in the Illinois Wind region and lower hydrology in the Maritime Hydro region compared to the third quarter of the previous year. The decreased production in the Renewable Energy Division was partially offset by increased wind resources in the Manitoba Wind region and increased hydrology in the Ontario region as the Long Sault Hydro Facility was online for the full quarter, compared to the same quarter in the prior year. This level of production represents sufficient renewable energy to supply the equivalent of 104,800 homes on an annualized basis with renewable power. As a result of renewable energy production, the equivalent of 259,160 tons of CO_2 gas was prevented from entering the atmosphere in the third quarter 2014.

During the quarter ended September 30, 2014, the division generated electricity equal to 88.2% of long-term projected average resources (wind, hydrology, and solar), as compared to 94.2% during the same period in 2013. In the third quarter of 2014, the Ontario and Western Hydro regions produced 6% to 13% above long-term average resources, while the Texas and Manitoba Wind regions achieved production approximately at long-term averages. The Quebec and Maritime Hydro regions and Saskatchewan, Pennsylvania, and Illinois Wind regions produced 7% to 30% lower than long-term average resources.

For the quarter ended September 30, 2014, the Cornwall Solar Facility generated 5.2 GW-hrs of electricity, which is 14.6% above long-term projected average resources. The facility achieved commercial operation on March 27, 2014 and has a 20 year FIT Power Purchase Agreement with the Ontario Power Authority.

For the quarter ended September 30, 2014, revenue from energy sales in the Renewable Energy Division totalled $29.9 million, as compared to $28.6 million during the same period in 2013, an increase of $1.3 million. As the purchase of energy by AES is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's sales results. For the quarter ended September 30, 2014, net energy sales in the Renewable Energy Division totalled $26.9 million, as compared $26.5 million during the same period in 2013, an increase of $0.4 million.

Revenue from generation at APCo's hydro facilities located in the Ontario, Quebec and Western Hydro regions totalled $13.3 million as compared to $14.1 million during the same period in 2013 (including business interruption insurance proceeds for the Long Sault Hydro Facility). The decrease is mainly attributed to lower weighted average energy rates combined with lower revenues at the Long Sault Hydro Facility compared to the business interruption insurance proceeds received in the third quarter of 2013. Revenue from APCo's hydro facility located in the Maritime region decreased $0.2 million primarily due to lower hydrology.

Revenue from APCo's wind facilities located in the Manitoba region increased $0.9 million due to favorable wind resources at the St. Leon Wind facilities. Revenues from APCo's U.S. wind facilities located in Illinois, Pennsylvania and Texas regions decreased by $1.0 million, primarily caused by unfavorable pricing, partially offset by a favorable U.S. dollar foreign exchange rate and increased production.

Revenue from generation at APCo's new solar facility located in Cornwall, Ontario totalled $2.4 million for the quarter ended September 30, 2014. The facility achieved commercial operation on March 27, 2014 and therefore there is no comparative data from the previous year.

For the three months ended September 30, 2014, revenue at AES decreased $0.2 million or 4.6%, primarily due to lower average pricing offset by increased customer load served. Revenue at AES primarily consists of wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine, merchant sales of production in excess of committed customer deliveries from the Tinker Facility, and other revenue.

For the quarter ended September 30, 2014, energy purchase costs by AES totalled $2.8 million as compared to $1.6 million during the same period in 2013, an increase of $1.2 million. AES increased energy purchase costs for the quarter ended September 30, 2014,were primarily due to lower hydrology in the Maritime Hydro region, which caused a higher volume of energy purchases from external suppliers at higher average prices. During this period, AES purchased approximately 54.4 GW-hrs of energy at market and fixed rates averaging U.S. $47 per MW-hr. During the quarter, the Maritime region generated approximately 25% of the load required to service its customers as well as AES' customers, as compared to 76% in the same period in 2013. To mitigate the risk of higher average energy prices, AES had previously entered into certain power hedges as part of its risk mitigation strategies. For the quarter ended September 30, 2014, $0.2 million was realized in connection with these hedges and is recorded as a realized loss on derivative financial instruments on the unaudited interim Consolidated Statement of Operations.

For the quarter ended September 30, 2014, REC revenue totalled $1.3 million, which is consistent with the prior period. 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 quarter ended September 30, 2014, REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities.

The Red Lily I Wind Facility located in Saskatchewan produced 16.0 GW-hrs of electricity for the quarter ended September 30, 2014. APCo's economic return from its investment in Red Lily 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, APCo 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 quarter ended September 30, 2014, APCo earned fees of $0.2 million (which is classified as other revenue) and interest income of $0.4 million from the Red Lily I Wind Facility.

For the quarter ended September 30, 2014, operating expenses excluding energy purchases totalled $12.1 million, as compared to $10.5 million during the same period in 2013, an increase of $1.6 million. The increase was primarily attributable to operating costs at the new Cornwall Solar Facility, a full quarter of operations at Long Sault in 2014, a stronger U.S. dollar exchange rate, and increased repair costs and professional fees in the Illinois Wind region.

For the quarter ended September 30, 2014, interest and other income totalled $0.5 million, consistent with the same period in 2013. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility. This amount is included as part of APCo's earnings from its investment in the Red Lily I Wind Facility, as discussed above.

For the quarter ended September 30, 2014, the value of net tax attributes generated amounted to an approximate HLBV income of $2.3 million, an increase of $1.3 million compared to the prior year. The increase was attributable to increased production, a stronger U.S. dollar exchange rate, and the reduced economic interest in the projects attributable to tax equity.

For the quarter ended September 30, 2014, the Renewable Energy Division's operating profit totalled $19.1 million, as compared to $19.2 million during the same period in 2013, a decrease of $0.1 million. As a result of the stronger U.S. dollar, operating profit increased by $0.2 million.

APCo: Thermal Energy Division

2014 Nine Month Operating Results

	Nine months ended September 30, 2014			Nine months ended September 30, 2013		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance(GW-hrs sold)	**86.1**	**99.0**	**185.1**	86.5	101.9	188.4
Performance(steam sales – billion lbs)	**451.8**	**—**	**451.8**	461.6	—	461.6
(all amounts in millions)						
Revenue						
Energy/steam sales	**$ 18.3**	**$ 15.5**	**$ 33.8**	$ 13.0	$ 13.0	$ 26.0
Less:						
Cost of Sales – Fuel	**(12.2)**	**(5.5)**	**(17.7)**	(8.1)	(4.4)	(12.5)
Net Energy/Steam Sales	**$ 6.1**	**$ 10.0**	**$ 16.1**	$ 4.9	$ 8.6	$ 13.5
Other revenue	**1.2**	**1.3**	**2.5**	0.3	1.4	1.7
Total net revenue	**$ 7.3**	**$ 11.3**	**$ 18.6**	$ 5.2	$ 10.0	$ 15.2
Expenses						
Operating expenses	**(3.7)**	**(3.7)**	**(7.4)**	(2.8)	(3.6)	(6.4)
Facility operating profit	**$ 3.6**	**$ 7.6**	**$ 11.2**	$ 2.4	$ 6.4	$ 8.8
Interest and other income			**(0.2)**			0.1
Divisional operating profit			**$ 11.0**			$ 8.9

APCo'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.

Production data, revenue and expenses have been adjusted to remove the results of the EFW Facility and BCI Facility, which are now sold. See Financial Statement note 12 for details.

For the nine months ended September 30, 2014, the Thermal Energy Division produced 185.1 GW-hrs of electrical energy, as compared to 188.4 GW-hrs of electrical energy in the comparable period of 2013. The decrease in production is due to Sanger's planned outage and limitation of run hours in the first quarter of 2014.

For the nine months ended September 30, 2014, the Thermal Energy Division's operating profit was $11.0 million, as compared to $8.9 million in the same period in 2013, an increase of $2.1 million. The Windsor Locks Thermal Facility contributed $3.6 million, while the Sanger Thermal Facility contributed $7.6 million of operating profit during the nine months ended September 30, 2014, as compared to $2.4 million and $6.4 million, respectively, during the same period in the prior year. Interest and other income for the nine months ended September 30, 2014 was nil as compared to income of $0.1

million during the same period in the prior year. As a result of the stronger U.S. dollar, operating profit increased by $0.7 million.

Windsor Locks Thermal Facility

For the nine months ended September 30, 2014, the Windsor Locks Thermal Facility sold 451.8 billion lbs of steam and 86.1 GW-hrs of electricity, as compared to 461.6 billion lbs of steam and 86.5 GW-hrs of electricity in the comparable period of 2013.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $18.3 million, as compared to $13.0 million in the same period in 2013. The increase in electricity/steam sales is attributed to a higher average price for gas as a result of the better ISO NE electricity market price driven by seasonally low temperatures in the first half of 2014. Gas costs for the period were $12.2 million, as compared to $8.1 million in the same period in 2013. The increase in gas costs is a result of a 35% increase in the average landed cost of natural gas per MMBTU and a 3% increase in the volume of natural gas consumed, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the nine months ended September 30, 2014, net energy/steam sales at the Windsor Locks Thermal Facility totalled $6.1 million, as compared to $4.9 million during the same period in 2013, an increase of $1.2 million resulting from a stronger U.S. dollar exchange rate and increased pricing of electricity and steam sales.

Operating expenses excluding natural gas costs were $3.7 million, as compared to $2.8 million during the same period in 2013. The increase is primarily attributable to the cost of RECs sold in the first nine months of 2014 for which costs were inventoried in 2013, a stronger US dollar, and increased expenses related to repair & maintenance, labour and administration costs. The Windsor Locks Thermal Facility's resulting net operating income for the nine months ended September 30, 2014 was $3.6 million, as compared to $2.4 million in the same period in 2013, an increase of $1.2 million.

Sanger Thermal Facility

The Sanger Thermal Facility's operating profit was driven by energy/steam sales of $15.5 million, as compared to $13.0 million in the same period in 2013, an increase of $2.5 million. The increase in energy/steam sales is attributed primarily to increased gas prices, which is a pass through to customers as it is reflected in higher market prices as compared to the same period in 2013. Capacity revenues remained unchanged at $6.7 million. Gas costs for the period were $5.5 million, as compared to $4.4 million in the same period in 2013. The increase in gas costs is due to a 25% increase in the average cost of natural gas per MMBTU, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the nine months ended September 30, 2014, net energy sales at the Sanger Thermal Facility totalled $10.0 million, as compared to $8.6 million during the same period in 2013, an increase of $1.4 million primarily due to more favorable pricing on the variable portion of the supply contract.

Operating expenses excluding natural gas costs were $3.7 million, which was consistent with the same period in 2013. The Sanger Thermal Facility's resulting net operating income for the nine months ended September 30, 2014 was $7.6 million, as compared to $6.4 million in the same period in 2013, an increase of $1.2 million.

2014 Third Quarter Operating Results

		Three months ended September 30, 2014						Three months ended September 30, 2013				
		Windsor Locks		Sanger		Total		Windsor Locks		Sanger		Total
Performance(GW-hrs sold)		**28.2**		**36.7**		**64.9**		28.6		34.8		63.4
Performance(steam sales – billion lbs)		**111.8**		**—**		**111.8**		116.3		—		116.3
(all amounts in millions)												
Revenue												
Energy/steam sales	**$**	**3.4**	**$**	**7.0**	**$**	**10.4**	$	3.5	$	5.7	$	9.2
Less:												
Cost of Sales – Fuel		**(2.0)**		**(2.0)**		**(4.0)**		(2.0)		(1.5)		(3.5)
Net Energy/Steam Sales	**$**	**1.4**	**$**	**5.0**	**$**	**6.4**	$	1.5	$	4.2	$	5.7
Other revenue		**0.3**		**0.6**		**0.9**		—		0.5		0.5
Total net revenue	**$**	**1.7**	**$**	**5.6**	**$**	**7.3**	$	1.5	$	4.7	$	6.2
Expenses												
Operating expenses		**(0.9)**		**(1.3)**		**(2.2)**		(0.3)		(0.9)		(1.2)
Facility operating profit	**$**	**0.8**	**$**	**4.3**	**$**	**5.1**	$	1.2	$	3.8	$	5.0
Interest and other income						**(0.2)**						0.3
Divisional operating profit					**$**	**4.9**					$	5.3

APCo'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.

Production data, revenue and expenses have been adjusted to remove the results of the EFW Facility and BCI Facility which is now sold. See Financial Statement note 12 for details.

For the three months ended September 30, 2014, the Thermal Energy Division produced 64.9 GW-hrs of electrical energy, as compared to 63.4 GW-hrs of electrical energy in the comparable period of 2013. The Windsor Locks facility generated similar production, as compared to the comparable period in 2013. The increased production at the Sanger Thermal Facility is due to additional hours of runtime intended to take advantage of the higher than normal contract basis differential.

For the three months ended September 30, 2014, the Thermal Energy Division's operating profit was $4.9 million, as compared to $5.3 million in the same period in 2013, a decrease of $0.4 million. Operating profit contributions for the three months ended September 30, 2014 were $0.8 million from the Windsor Locks Thermal Facility and $4.3 million from the Sanger Thermal Facility, as compared to $1.2 million and $3.8 million respectively, during the same period in the prior year. Interest and other income for the three months ended September 30, 2014 was nil, as compared to income of $0.3 million during the same period in the prior year due to a temporary shutdown in the operations at the Valley Power Partnership. As a result of the stronger U.S. dollar, operating profit increased by $0.3 million.

Windsor Locks Thermal Facility

For the three months ended September 30, 2014, the Windsor Locks Thermal Facility sold 111.8 billion lbs of steam and 28.2 GW-hrs of electricity, as compared to 116.3 billion lbs of steam and 28.6 GW-hrs of electricity in the comparable period of 2013.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $3.4 million and gas costs for the period of $2.0 million, which were consistent with the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended

September 30, 2014, net sales at the Windsor Locks Thermal Facility totalled $1.4 million, which was consistent with the same period in 2013.

Operating expenses excluding natural gas costs were $0.9 million, as compared to $0.3 million in the same period in 2013. The increase was primarily due to increased repair & maintenance, labour and administration costs and the appreciation of the US currency. The Windsor Locks Thermal Facility's resulting net operating income for the three months ended September 30, 2014 was $0.8 million as compared to $1.2 million in the same period in 2013.

Sanger Thermal Facility

The Sanger Thermal Facility's operating profit was driven by energy/steam sales of $7.0 million, as compared to $5.7 million in the same period in 2013, an increase of $1.3 million. The increase in energy/steam sales is primarily due to a 27% increase in price largely due to the increase in contract basis differential, as compared to the same period in 2013. Capacity revenues remained unchanged at $3.3 million. Gas costs for the period were $2.0 million, as compared to $1.5 million in the same period in 2013. The increase in gas costs is due to a 3% increase in the volume of natural gas consumed and a 17% increase in the average cost of natural gas per MMBTU, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended September 30, 2014, net energy sales at the Sanger Thermal Facility totalled $5.0 million, as compared to $4.2 million during the same period in 2013, an increase of $0.8 million.

Operating expenses excluding natural gas costs were $1.3 million, as compared to $0.9 million in the same period in 2013. The Sanger Thermal Facility's resulting net operating income for the three months ended September 30, 2014 was $4.3 million, as compared to $3.8 million in the same period in 2013, an increase of $0.5 million.

APCo: 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 APCo's existing portfolio.

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

Project Name	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GW-hrs
Projects in Construction						
Morse Wind[1]	Saskatchewan	23	$ 81.3	2015	20	104.0
St. Damase[1,2,4]	Quebec	24	$ 65.0	2014	20	76.9
Bakersfield Solar[1,5]	California	20	$ 65.5	Q1 2015	20	53.3
		67	**$ 211.8**			**234.2**
Projects in Development						
Chaplin Wind[1]	Saskatchewan	177	$ 340.0	2016	25	720.0
Amherst Island[1]	Ontario	75	$ 260.0	2016	20	247.0
Odell Wind Project [1,6]	Minnesota	200	$ 361.5	2015	20	821.1
Val Eo - Phase I[1,3,4]	Quebec	24	$ 70.0	2015	20	66.0
		476	**$ 1,031.5**			**1,854.1**
Total		**543**	**$ 1,243.3**			**2,088.3**

[1] PPA signed

[2] The St. Damase project is being developed in two phases: Phase I of the project (24 MW) will be erected in 2014 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] The Val Eo project is being developed in two phases: Phase I of the project (24 MW) will be erected in 2015 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.

[4] Size, Estimated Capital Costs, Commercial Operation Date, PPA Term and Production refer solely to Phase I of the St. Damase and Val-Eo wind projects.

[5] Total cost of the project is expected to be approximately $58.5 million in U.S. dollars.

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

Morse Wind Project

The 23 MW project is under construction near Morse, Saskatchewan, approximately 180 km west of Regina. The project has additional land under lease to facilitate future expansion. The Project has a 23 MW PPA with SaskPower. The turbine supply agreements have been executed with Siemens and the Balance of Plant Engineering, Procurement and Construction agreement has been signed. The turbine placement has been finalized and registered land leases have been executed with the landowners. Installation of access roads and foundations are completed, turbines are scheduled for delivery in January 2015, and commercial operation is expected to occur before March 31, 2015.

Saint-Damase Wind Project

Phase I of the Saint-Damase Wind Project is under construction in the local municipality of Saint-Damase, in the Gaspe Peninsula. The initial phase of the project is a 24 MW facility located near St. Damase, Quebec in a partnership with the Municipality of Saint-Damase. The Saint-Damase wind project has signed a 20 year PPA with Hydro Quebec and has projected capital costs of $65 million. On June 25, 2013, the partnership executed an interconnection agreement with Hydro Quebec. The permitting and the environmental impact assessment were completed and the construction of the first project phase started in late first quarter of 2014. Erection of all turbines at the Saint-Damase Wind Project is complete and the commercial operation date is expected to occur within the next 30 days.

It is expected that the turbines and other components utilized in the first 24 MW phase of the Saint-Damase Wind Project will qualify as Canadian Renewable and Conservation Expense ("CRCE"), and therefore a significant portion of the Phase I capital cost will be eligible for a refundable Quebec tax credit ("Quebec CRCE Tax Credit"). In June 2014, the government of Quebec released the 2014-2015 budget, which included a 20% reduction in value for a wide range of tax credits, including the Quebec CRCE Tax Credit. The estimated value of the Quebec CRCE tax credit for the Saint-Damase project is now expected to be approximately $16.4 million. 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.

Bakersfield Solar Project

The Bakersfield Solar Project is under construction in Kern County, California. The project is a 20 MWac solar powered generating station, which is expected to generate 53.3 GW-hrs of energy per year. All energy from the project will be sold to PG&E pursuant to a 20 year agreement. Total expected capital costs for the project will be U.S. $58.5 million.

Construction of the project commenced in the second quarter of 2014. Pile driving is near completion and racking installations are in full production. The construction of the interconnections is underway and photovoltaic panels continue to be installed. The substation main transformer has been placed and associated equipment foundations are near completion. All major equipment for the project has been procured, with deliveries continuing to be received on site as planned.

On August 13, 2014, APCo entered into a definitive partnership agreement with a third party (the "Tax Investor"), pursuant to which the Tax Investor will contribute U.S. $22.0 million towards the capital cost of the project. With its partnership interest, the Tax Investor will receive the majority of the tax attributes associated with the project.

Commencement of operations is planned for the first quarter of 2015.

Chaplin Wind Project

In 2012, APCo entered into a 25 year PPA with SaskPower for development of a 177 MW wind power project in the rural Municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

In March 2014, after review of the Project Proposal (Environmental Assessment) and Supplemental documentation (including the preliminary proposed layout), the project was deemed a development by the Environmental Assessment Branch. An additional detailed environmental review is currently being completed. It is anticipated the submission of the Environmental Assessment documentation will be submitted to the government in late Q4 2014 or early Q1 2015. The expected capital costs of the project are approximately $340 million. The project will be split into two phases. The first phase will involve installing test turbines to prove the project viability. The second phase, the infill construction phase, will only commence providing the results of the first phase are successful. APCo intends to enter into a partnership agreement using a similar structure to what was utilized in the development of the Red Lily I facility, in order to facilitate the development of the project and to optimize returns

Amherst Island Wind Project

The Amherst Island Wind Project is located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario. In February 2011, the 75 MW project was awarded a Feed in Tariff ("FIT") contract by the OPA as part of the second round of the OPA's FIT program.

The Renewable Energy Approval ("REA") application was submitted in April 2013 and posted to the environmental registry in early January 2014. The REA has now been issued in draft form for comment. APUC has provided its comments back to the Ontario Ministry of the Environment requesting certain technical changes. Once the REA is issued in final form, 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 a maximum of 6 months. The project has a planned construction time frame of 12 to 18 months with most of the construction expected to occur in 2016.

The Amherst Island Wind Project currently expects to use wind Class III large-rotor direct drive wind turbine generator technology. Due to delays in the regulatory approval process, changes in the foreign exchange rates and more detailed engineering estimates, total capital cost are now expected to be approximately $260 million.

Odell Wind Project

On September 4, 2014, APCo announced an opportunity to acquire an interest in the Odell Wind Farm LLC ("Odell"), which owns a 200 MW construction-stage wind development project ("Odell Wind Project") in the state of Minnesota. APCo is continuing its engineering, regulatory and financial analysis in respect of the Odell Wind Project to ensure that it meets all of APCo's requirements for an approved development project.

The Odell Wind Project is located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota and is being constructed on approximately 23,000 acres of leased land. The project will utilize 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year power purchase agreement, all energy, capacity and renewable energy credits from the Odell Wind Project will be sold to Northern States Power Company, a subsidiary of Xcel Energy Inc., which is a diversified utility operating in the midwest U.S. The total construction costs of the Odell Wind Project are estimated to be U.S. $322.8 million. It is anticipated that the Odell Project will qualify for U.S. federal production tax credits having satisfied the Internal Revenue Service 5% beginning of construction investment safe-harbor guidance. Accordingly, approximately 60% of the permanent project financing is expected to be funded by tax equity investors. APCo's share of the balance will be financed through a private placement of subscription receipts to Emera Inc. and long term debt.

Ontario RFP Qualification

APCo has qualified for participation in the anticipated 2015 Large Renewable Procurement I process with the Ontario Power Authority. APCo may submit offers into the expected RFP for up to 100 MW of solar power and up to 100 MW of wind power . The OPA is expected to award up to 140 MW of solar projects and 300 MW of wind projects. RFP bids are due by May 2015, with successful bidders being announced in July 2015.

DISTRIBUTION AND TRANSMISSION: LIBERTY UTILITIES

Liberty Utilities is a diversified rate-regulated utility providing distribution and transmission services to approximately 488,100 connections in the natural gas, electric, water and wastewater sectors. Liberty Utilities' strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. Liberty Utilities believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

Utility System Type	September 30, 2014			September 30, 2013		
(all dollar amounts in U.S. $ millions)		Assets	Connections		Assets	Connections
Electricity	$	306.8	92,900	$	268.7	91,500
Natural Gas		697.8	292,100		569.4	232,500
Water and Wastewater		242.2	103,100		234.4	97,000
Total	$	1,246.8	488,100	$	1,072.5	$ 421,000
Accumulated Deferred Income Taxes	$	91.8		$	60.4	

	Three months ended September 30,				Nine months ended September 30,			
(all dollar amounts in U.S. $ millions)		2014		2013		2014		2013
Revenue								
Utility electricity sales and distribution	**$**	**44.9**	$	41.2	**$**	**139.1**	$	119.2
Less: Cost of Sales – Electricity		**(25.2)**		(23.0)		**(78.9)**		(69.3)
Net Utility Sales - Electricity	**$**	**19.7**	$	18.2	**$**	**60.2**	$	49.9
Utility natural gas sales and distribution	**$**	**36.1**	$	25.5	**$**	**275.9**	$	152.6
Less: Cost of Sales – Natural Gas		**(12.7)**		(7.6)		**(169.4)**		(90.5)
Net Utility Sales - Natural Gas	**$**	**23.4**	$	17.9	**$**	**106.5**	$	62.1
Net Utility Sales - Water Distribution & Wastewater Treatment		**15.8**		15.3		**44.1**		41.6
Gas Transportation		**2.8**		2.5		**16.8**		12.3
Other Revenue		**0.7**		—		**2.0**		—
Net Utility Sales	**$**	**62.4**	$	53.9	**$**	**229.6**	$	165.9
Operating expenses		**(40.1)**		(33.8)		**(122.7)**		(93.6)
Other income		**0.6**		0.1		**1.9**		2.3
Liberty Utilities operating profit	**$**	**22.9**	$	20.2	**$**	**108.8**	$	74.6

Liberty Utilities reports the performance of its utility operations by geographic region: West, Central, and East.

The Liberty Utilities (West) region is comprised of regulated electrical and water distribution and wastewater collection utility systems and serves approximately 117,700 connections in the states of Arizona and California.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems and serves approximately 119,700 connections located in the states of Arkansas, Illinois, Iowa, Missouri, and Texas.

The Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems and serves approximately 250,700 connections located in the states of Georgia, Massachusetts, and New Hampshire.

For the three and nine months ended September 30, 2014, Liberty Utilities reported an operating profit of U.S. $22.9 million and U.S. $108.8 million, as compared to U.S. $20.2 million and U.S. $74.6 million for the comparable periods in the prior year. The increase is primarily due to higher rates for the Granite State Electric and Peach State Gas Systems and the acquisition of the New England Gas System. Detailed results are discussed in the following sections.

Liberty Utilities: West Region

	Nine months ended September 30,	
	2014	**2013**
Average Active Electric Connections For The Period		
Residential	41,900	41,000
Commercial and Industrial	5,700	5,500
Total Average Active Electric Connections For The Period	**47,600**	**46,500**
Average Active Number of Water Connections For The Period		
Wastewater connections	31,600	30,600
Water distribution connections	34,600	33,800
Total Average Active Water Connections For The Period	**66,200**	**64,400**
Customer Usage (GW-hrs)		
Residential	195.1	204.4
Commercial and Industrial	198.5	199.9
Total Customer Usage (GW-hrs)	**393.6**	**404.3**
Gallons Provided		
Wastewater treated (millions of gallons)	1,274	1,241
Water sold (millions of gallons)	3,837	3,795
Total Gallons Provided	**5,111**	**5,036**

For the nine months ended September 30, 2014, the Liberty Utilities (West) region's electricity usage totalled 393.6 GW-hrs, as compared to 404.3 GW-hrs for the same period in 2013, a decrease of 10.7 GW-hrs. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues will not be impacted by fluctuations in customer demand due to the variations in the weather conditions and changes in the number of customers. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement each month. The electricity commodity continues to be passed through to the CalPeco Electric System's customers according to their consumption.

During the nine months ended September 30, 2014, the Liberty Utilities (West) region provided approximately 3,837 million gallons of water to its customers and treated approximately 1,274 million gallons of wastewater, as compared to 3,795 million gallons of water and 1,241 million gallons of wastewater during the same period in 2013 mainly due to the increase in connection counts.

2014 Nine Month Operating Results

	Nine months ended September 30,		Nine months ended September 30,	
	2014 U.S. $ (millions)	2013 U.S. $ (millions)	**2014 Can $ (millions)**	2013 Can $ (millions)
Water Assets for regulatory purposes	**182.0**	181.5		
Electricity Assets for regulatory purposes	**186.8**	173.0		
Revenue				
Utility electricity sales and distribution	**$ 54.8**	$ 55.7	**$ 60.0**	$ 57.1
Less: Cost of Sales – Electricity	**(27.2)**	(28.1)	**(29.7)**	(28.8)
Net Utility Sales - Electricity	**$ 27.6**	$ 27.6	**$ 30.3**	$ 28.3
Wastewater treatment	**$ 14.2**	$ 13.9	**$ 15.5**	$ 14.3
Water distribution	**15.5**	14.6	**17.0**	14.9
Net Utility Sales	**$ 57.3**	$ 56.1	**$ 62.8**	$ 57.5
Expenses				
Operating expenses	**(25.0)**	(26.4)	**(27.3)**	(27.1)
Other income	**0.9**	1.1	**1.2**	1.2
Division operating profit	**$ 33.2**	$ 30.8	**$ 36.7**	$ 31.6

The purchase of electricity by the Liberty Utilities (West) region is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, the Liberty Utilities (West) region compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the nine months ended September 30, 2014, net utility sales for the Liberty Utilities (West) region were U.S. $57.3 million, as compared to U.S. $56.1 million for the same period in 2013, an increase of U.S. $1.2 million or 2.1%.

For the nine months ended September 30, 2014, the Liberty Utilities (West) region's revenue from utility electricity sales totalled U.S. $54.8 million, as compared to U.S. $55.7 million during the same period in 2013, a decrease of U.S. $0.9 million or 1.6%. For the nine months ended September 30, 2014, fuel and purchased power costs for the Liberty Utilities (West) region totalled U.S $27.2 million, as compared with U.S. $28.1 million for the same period in 2013, a decrease of U.S. $0.9 million. The net utility sales from the electric utility were U.S. $27.6 million, which was consistent with the same period in 2013. Under the base rate revenue decoupling mechanism, the CalPeco Electric System's base rate revenues will not be impacted by fluctuations in customer demand due to the variations in weather conditions and changes in the number of customers.

For the nine months ended September 30, 2014, revenue from wastewater treatment and water distribution totalled U.S. $14.2 million and U.S. $15.5 million, respectively, as compared to U.S. $13.9 million and U.S. $14.6 million, respectively, during the same period in 2013. The total increase in wastewater treatment and water distribution revenue was primarily due to an increase in rates resulting from the most recent rate case, as compared to the same period in 2013.

For the nine months ended September 30, 2014, operating expenses, excluding electricity purchases, totalled U.S. $25.0 million, as compared to U.S. $26.4 million during the same period in 2013. The decrease in operating expenses can be primarily attributed to lower labour expenses, as compared to the same period in the prior year.

For the nine months ended September 30, 2014, the Liberty Utilities (West) region's operating profit was U.S. $33.2 million, as compared to U.S. $30.8 million in the same period in 2013, an increase of U.S. $2.4 million or 7.8%.

Measured in Canadian dollars, the Liberty Utilities (West) region's operating profit was $36.7 million, as compared to $31.6 million in the same period in 2013.

	Three months ended September 30,	
	2014	2013
Average Active Electric Connections For The Period		
Residential	42,000	41,500
Commercial and Industrial	5,600	5,400
Total Average Active Electric Connections For The Period	**47,600**	**46,900**
Average Active Number of Water Connections For The Period		
Wastewater connections	31,800	30,600
Water distribution connections	34,900	34,000
Total Average Active Water Connections For The Period	**66,700**	**64,600**
Customer Usage (GW-hrs)		
Residential	58.0	58.2
Commercial and Industrial	64.0	65.3
Total Customer Usage (GW-hrs)	**122.0**	**123.5**
Gallons Provided		
Wastewater treated (millions of gallons)	386	383
Water sold (millions of gallons)	1,583	1,585
Total Gallons Provided	**1,969**	**1,968**

For the three months ended September 30, 2014, the Liberty Utilities (West) region's electricity usage totalled 122.0 GW-hrs, as compared to 123.5 GW-hrs for the same period in 2013, a decrease of 1.5 GW-hrs. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues will not be impacted by fluctuations in customer demand due to the variations in the weather conditions and changes in the number of customers. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement each month. The electricity commodity continues to be passed through to the CalPeco Electric System's customers according to their consumption.

During the three months ended September 30, 2014, the Liberty Utilities (West) region provided approximately 1,583 million gallons of water to its customers and treated approximately 386 million gallons of wastewater, as compared to 1,585 million gallons of water and 383 million gallons of wastewater during the same period in 2013.

2014 Third Quarter Operating Results

	Three months ended September 30,		Three months ended September 30,	
	2014 U.S. $ (millions)	2013 U.S. $ (millions)	**2014 Can $ (millions)**	2013 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 17.9**	$ 17.7	**$ 19.5**	$ 18.5
Less: Cost of Sales – Electricity	**(8.8)**	(8.6)	**(9.6)**	(8.9)
Net Utility Sales - Electricity	**$ 9.1**	$ 9.1	**$ 9.9**	$ 9.6
Wastewater treatment	**$ 4.8**	$ 4.7	**$ 5.2**	$ 4.9
Water distribution	**6.0**	5.6	**6.5**	5.7
Net Utility Sales	**$ 19.9**	$ 19.4	**$ 21.6**	$ 20.2
Expenses				
Operating expenses	**(8.2)**	(8.8)	**(9.0)**	(9.2)
Other income	**0.4**	0.3	**0.4**	0.3
Division operating profit	**$ 12.1**	$ 10.9	**$ 13.0**	$ 11.3

The purchase of electricity by the Liberty Utilities (West) region is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, the Liberty Utilities (West) region compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the three months ended September 30, 2014, net utility sales for the Liberty Utilities (West) region were U.S. $19.9 million, as compared to U.S. $19.4 million during the same period in 2013, an increase of U.S. $0.5 million, or 2.6%, primarily driven by higher water distribution and wastewater treatment revenues due to an increase in rates.

For the three months ended September 30, 2014, the Liberty Utilities (West) region's revenue from utility electricity sales totalled U.S. $17.9 million, as compared to U.S. $17.7 million during the same period in 2013, an increase of U.S. $0.2 million. For the three months ended September 30, 2014, fuel and purchased power costs for the Liberty Utilities (West) region totalled U.S $8.8 million, as compared to U.S. $8.6 million during the same period in 2013. The net utility sales from the electric utility were U.S. $9.1 million, which was consistent with the same period in 2013. Under the base rate revenue decoupling mechanism, the CalPeco Electric System's base rate revenues will not be impacted by fluctuations in customer demand due to the variations in weather conditions and changes in the number of customers.

For the three months ended September 30, 2014, revenue from wastewater treatment and water distribution totalled U.S. $4.8 million and U.S. $6.0 million, respectively, as compared to U.S. $4.7 million and U.S. $5.6 million, respectively, during the same period in 2013. The total increase in wastewater treatment and water distribution revenue was primarily due to an increase in rates, as compared to the same period in 2013.

For the three months ended September 30, 2014, operating expenses, excluding electricity purchases, totalled U.S. $8.2 million, as compared to U.S. $8.8 million during the same period in 2013, a decrease of $0.6 million, or 7%. The decrease in operating expenses can be primarily attributed to lower labour expenses, as compared to the same period in the prior year.

For the three months ended September 30, 2014, the Liberty Utilities (West) region's operating profit was U.S. $12.1 million, as compared to U.S. $10.9 million in the same period in 2013, an increase of U.S. $1.2 million, or 11.0%.

Measured in Canadian dollars, the Liberty Utilities (West) region's operating profit was $13.0 million, as compared to $11.3 million in the same period in 2013.

Liberty Utilities: Central Region

	Nine months ended September 30, 2014	2013
Average Active Natural Gas Connections For The Period		
Residential	70,400	71,600
Commercial and Industrial	9,200	9,200
Total Average Active Natural Gas Connections For The Period	**79,600**	**80,800**
Average Active Water Connections For The Period		
Wastewater connections	6,900	6,000
Water distribution connections	22,600	21,900
Total Average Active Water Connections For The Period	**29,500**	**27,900**
Customer Usage (MMBTU)		
Residential	4,476,000	3,879,000
Commercial and Industrial	2,827,000	2,408,200
Total Customer Usage (MMBTU)	**7,303,000**	**6,287,200**
Gallons Provided		
Wastewater treated (millions of gallons)	318	285
Water sold (millions of gallons)	2,532	2,286
Total Gallons Provided	**2,850**	**2,571**

The Liberty Utilities (Central) region acquired the Pine Bluff Water System on February 1, 2013. Consequently, there is one additional month of operations from this utility in the first nine months of 2014 as compared to the first nine months of 2013.

The Liberty Utilities (Central) region acquired the White Hall Water and Sewer System on May 30, 2014. Consequently, there are four additional months of operations from this utility in the first nine months of 2014 as compared to the first nine months of 2013.

For the nine months ended September 30, 2014, the Liberty Utilities (Central) region natural gas distribution sales totalled 7,303,000 MMBTU, as compared to 6,287,200 MMBTU during the same period in 2013, an increase of 1,015,800 MMBTU, or 16%. The increase in volumes can be primarily attributed to the below-seasonal temperatures experienced in the first quarter of 2014, as compared to 2013.

During the nine months ended September 30, 2014, the Liberty Utilities (Central) region provided approximately 2,532 million gallons of water to its customers and treated approximately 318 million gallons of wastewater, as compared to 2,286 million gallons of water and 285 million gallons of wastewater during the same period in 2013. The increase in water sold can be primarily attributed to the additional month of operations from the Pine Bluff Water System in the first nine months of 2014, as compared to the first nine months of 2013. The increase in wastewater treated can be primarily attributed to the acquisition of the White Hall Water and Sewer System on May 30, 2014.

2014 Nine Month Operating Results

		Nine months ended September 30,		Nine months ended September 30,	
		2014 U.S. $ (millions)	2013 U.S. $ (millions)	**2014 Can $ (millions)**	2013 Can $ (millions)
Natural Gas Assets for regulatory purposes		**155.0**	144.3		
Water Assets for regulatory purposes		**60.2**	52.9		
Revenue					
Utility natural gas sales and distribution		**$ 57.9**	$ 50.8	**$ 63.5**	$ 51.7
Less: Cost of Sales – Natural Gas[1]		**(36.2)**	(30.5)	**(39.7)**	(30.8)
Net Utility Sales - Natural Gas		**$ 21.7**	20.3	**$ 23.8**	$ 20.9
Wastewater treatment		**$ 4.9**	$ 4.3	**$ 5.2**	$ 4.4
Water distribution		**9.5**	8.8	**10.6**	9.1
Gas Transportation		**2.7**	2.4	**3.0**	2.5
Net utility sales		**$ 38.8**	$ 35.8	**$ 42.6**	$ 36.9
Expenses					
Operating expenses		**(22.2)**	(20.3)	**(24.5)**	(20.9)
Other income		**0.1**	0.2	**0.2**	0.3
Division operating profit		**$ 16.7**	$ 15.7	**$ 18.3**	$ 16.3

[1] Natural Gas costs are shown net of U.S. $3.1 million of gas deferral debits due to over-collection of gas commodity costs for the first nine months of the year.

The purchase of natural gas by the Liberty Utilities (Central) region is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, the division compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the nine months ended September 30, 2014, net utility sales for the Liberty Utilities (Central) region totalled U.S. $38.8 million, as compared to U.S. $35.8 million during the same period in 2013, an increase of U.S. $3.0 million, or 8.4%, primarily due to higher gas consumption and increased water utility connections.

For the nine months ended September 30, 2014, the Liberty Utilities (Central) region's revenue from natural gas sales and distribution totalled U.S. $57.9 million, as compared to U.S. $50.8 million during the same period in 2013, an increase of U.S. $7.1 million, or 14.0%. For the nine months ended September 30, 2014, natural gas purchases for the Liberty Utilities (Central) region's natural gas utility totalled U.S $36.2 million, as compared with U.S. $30.5 million for the same period in 2013, an increase of U.S. $5.7 million. Net utility sales from the natural gas utilities, excluding transportation, were U.S. $21.7 million, as compared to U.S. $20.3 million during the same period in 2013, an increase of U.S. $1.4 million. The increase in net utility sales from the natural gas utilities is primarily attributed to higher customer usage resulting from below seasonal temperatures experienced in the first quarter of 2014, as compared to the same period in 2013.

For the nine months ended September 30, 2014, revenue from wastewater treatment and water distribution totalled U.S. $4.9 million and U.S $9.5 million, respectively, as compared to U.S. $4.3 million and U.S. $8.8 million, respectively, during the same period in 2013. The increase in total wastewater treatment and water distribution revenue can be primarily attributed to the additions of the Pine Bluff Water System on February 1, 2013 and the White Hall Water and Sewer System on May 30, 2014.

For the nine months ended September 30, 2014, the Liberty Utilities (Central) region's revenue from gas transportation sales totalled U.S. $2.7 million, as compared to U.S. $2.4 million during the same period in 2013, an increase of U.S. $0.3 million.

For the nine months ended September 30, 2014, operating expenses, excluding natural gas purchases, totalled U.S. $22.2 million, as compared to U.S. $20.3 million during the same period in 2013, an increase of U.S. 1.9 million, or 9.4%. The increase in operating expenses is primarily attributed to an additional month of operating expenses at the Pine Bluff Water System in the first nine months of 2014, as compared to the same period in 2013, as the utility was acquired on February

1, 2013, the acquisition of the White Hall Water and Sewer System on May 30, 2014, and increased employee and administrative expenses.

For the nine months ended September 30, 2014, the Liberty Utilities (Central) region's operating profit was U.S. $16.7 million, as compared to U.S. $15.7 million in the same period in 2013, an increase of U.S. $1.0 million.

Measured in Canadian dollars, the Liberty Utilities (Central) region's operating profit was $18.3 million, as compared to $16.3 million in the same period in 2013.

	Three months ended September 30,	
	2014	**2013**
Average Active Natural Gas Connections For The Period		
Residential	68,300	70,200
Commercial and Industrial	9,100	9,100
Total Average Active Natural Gas Connections For The Period	**77,400**	**79,300**
Average Active Water Connections For The Period		
Wastewater connections	7,700	6,100
Water distribution connections	23,400	21,900
Total Average Active Water Connections For The Period	**31,100**	**28,000**
Customer Usage (MMBTU)		
Residential	217,000	225,600
Commercial and Industrial	322,000	317,800
Total Customer Usage (MMBTU)	**539,000**	**543,400**
Gallons Provided		
Wastewater treated (millions of gallons)	145	96
Water sold (millions of gallons)	962	965
Total Gallons Provided	**1,107**	**1,061**

The Liberty Utilities (Central) region acquired the White Hall Water and Sewer System on May 30, 2014. Consequently, there are three additional months of operations from this utility in the third quarter of 2014, as compared to the third quarter of 2013.

For the three months ended September 30, 2014, the Liberty Utilities (Central) region natural gas distribution sales totalled 539,000 MMBTU, as compared to 543,400 MMBTU during the same period in 2013, a decrease of 4,400 MMBTU, or 0.8%.

During the three months ended September 30, 2014, the Liberty Utilities (Central) region provided approximately 962 million gallons of water to its customers and treated approximately 145 million gallons of wastewater, as compared to 965 million gallons of water and 96 million gallons of wastewater during the same period in 2013. The increase in wastewater treated can be primarily attributed to the acquisition of the White Hall Water and Sewer System on May 30, 2014. The White Hall Water and Sewer System provided approximately 41 million gallons of water to its customers during the three months ended September 30, 2014. Excluding the White Hall Water and Sewer System, the decrease in the gallons of water provided to customers can be primarily attributed to wetter weather experienced in the Texas and Midstates region during the three months ended September 30, 2014 as compared to the comparable period in the prior year.

2014 Third Quarter Operating Results

	Three months ended September 30,				Three months ended September 30,			
	2014 U.S. $ (millions)		2013 U.S. $ (millions)		**2014 Can $ (millions)**		2013 Can $ (millions)	
Revenue								
Utility natural gas sales and distribution	**$**	**7.4**	$	8.0	**$**	**8.0**	$	8.3
Less: Cost of Sales – Natural Gas[1]		**(2.1)**		(2.9)		**(2.2)**		(3.0)
Net Utility Sales - Natural Gas		**5.3**		5.1		**5.8**		5.3
Wastewater treatment		**1.8**		1.5		**1.9**		1.6
Water distribution		**3.2**		3.5		**3.6**		3.6
Gas Transportation		**0.1**		0.6		**0.1**		0.7
Net utility sales	**$**	**10.4**	$	10.7	**$**	**11.4**	$	11.2
Expenses								
Operating expenses		**(7.4)**		(7.2)		**(8.4)**		(7.5)
Other income		**—**		0.1		**—**		0.1
Division operating profit	**$**	**3.0**	$	3.6	**$**	**3.0**	$	3.8

[1] Natural Gas costs are shown net of U.S. $0.9 million of gas deferral debits due to over-collection of gas commodity costs in the quarter.

The purchase of natural gas by the Liberty Utilities (Central) region is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, the division compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the three months ended September 30, 2014, net utility sales for the Liberty Utilities (Central) region totalled U.S. $10.4 million, as compared to U.S $10.7 million during the same period in 2013, a decrease of U.S. $0.3 million, or 2.8% .

For the three months ended September 30, 2014, the Liberty Utilities (Central) region's revenue from natural gas sales and distribution totalled U.S. $7.4 million, as compared to U.S. $8.0 million during the same period in 2013, a decrease of U.S. $0.6 million. For the three months ended September 30, 2014, natural gas purchases for the Liberty Utilities (Central) region's natural gas utilities totalled U.S $2.1 million, as compared with U.S. $2.9 million for the same period in 2013, a decrease of U.S. $0.8 million. Net utility sales from the natural gas utilities were U.S. $5.3 million, as compared to U.S. $5.1 million during the same period in 2013.

For the three months ended September 30, 2014, revenue from wastewater treatment and water distribution totalled U.S. $1.8 million and U.S. $3.2 million, respectively, as compared to U.S. $1.5 million and U.S. $3.5 million, respectively, during the same period in 2013.

For the three months ended September 30, 2014, the Liberty Utilities (Central) region's revenue from gas transportation sales totalled U.S. $0.1 million, as compared to U.S. $0.6 million during the same period in 2013, a decrease of U.S. $0.5 million.

For the three months ended September 30, 2014, operating expenses, excluding natural gas purchases, totalled U.S. $7.4 million, as compared to U.S. $7.2 million during the same period in 2013, an increase of U.S. $0.2 million, or 2.8%. The increase in operating expenses can be primarily attributed to the acquisition of the White Hall Water and Sewer System on May 30, 2014.

For the three months ended September 30, 2014, the Liberty Utilities (Central) region's operating profit was U.S. $3.0 million, as compared to U.S. $3.6 million in the same period in 2013, a decrease of U.S. $0.6 million.

Measured in Canadian dollars, the Liberty Utilities (Central) region's operating profit was $3.0 million, as compared to $3.8 million in the same period in 2013.

Liberty Utilities: East Region

	Nine months ended September 30,	
	2014	**2013**
Average Active Natural Gas Connections For The Period		
Residential	178,200	128,600
Commercial and Industrial	17,100	13,500
Total Average Active Natural Gas Connections For The Period	**195,300**	**142,100**
Average Active Electric Connections For The Period		
Residential	36,500	36,800
Commercial and Industrial	6,600	6,500
Total Average Active Electric Connections For The Period	**43,100**	**43,300**
Customer Usage (GW-hrs)		
Residential	227.4	235.1
Commercial and Industrial	504.3	483.1
Total Customer Usage (GW-hrs)	**731.7**	**718.2**
Customer Usage (MMBTU)		
Residential	10,521,000	5,146,300
Commercial and Industrial	6,961,000	3,519,000
Total Customer Usage (MMBTU)	**17,482,000**	**8,665,300**

For the nine months ended September 30, 2014, the Liberty Utilities (East) region's electricity usage totalled 731.7 million GW-hrs and natural gas usage totalled 17,482,000 MMBTU, as compared to 718.2 GW-hrs and 8,665,300 MMBTU during the same period in 2013. The increase in natural gas usage, as compared to the same period in 2013, can be primarily attributed to the acquisitions of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013.

The Peach State Gas System usage totalled 4,959,000 MMBTU, while the New England Gas System usage totalled 4,220,000 MMBTU.

2014 Nine Month Operating Results

	Nine months ended September 30,		Nine months ended September 30,	
	2014 U.S. $ (millions)	2013 U.S. $ (millions)	**2014 Can $ (millions)**	2013 Can $ (millions)
Electricity Assets for regulatory purposes	**120.0**	95.8		
Natural Gas for regulatory purposes	**542.7**	425.1		
Revenue				
Utility electricity sales and distribution	**$ 84.3**	$ 63.5	**$ 92.3**	$ 65.0
Less: Cost of Sales – Electricity	**(51.7)**	(41.2)	**(56.6)**	(42.1)
Net Utility Sales - Electricity	**$ 32.6**	$ 22.3	**$ 35.7**	$ 22.9
Utility natural gas sales and distribution	**$ 218.0**	$ 101.8	**$ 239.4**	$ 103.5
Less: Cost of Sales – Natural Gas[1]	**(133.2)**	(60.0)	**(146.5)**	(60.9)
Net Utility Sales - Natural Gas	**$ 84.8**	$ 41.8	**92.9**	$ 42.6
Gas Transportation	**14.1**	9.9	**15.4**	10.0
Other Revenue	**2.0**	—	**2.2**	—
Net Utility Sales	**$ 133.5**	$ 74.0	**$ 146.2**	$ 75.5
Expenses				
Operating expenses	**(75.5)**	(46.9)	**(82.4)**	(47.9)
Other income	**0.9**	1.0	**1.1**	1.1
Division operating profit	**$ 58.9**	$ 28.1	**$ 64.9**	$ 28.7

1 Natural Gas costs are shown net of U.S. $18.3 million of gas deferral credits due to under-collection of gas commodity costs for the first six months of the year.

The cost of electricity and natural gas is passed through to the Liberty Utilities (East) region's customers. As a result, the division compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the nine months ended September 30, 2014, net utility sales for the Liberty Utilities (East) region totalled U.S. $133.5 million, as compared to U.S. $74.0 million during the same period in 2013, an increase of U.S. $59.5 million primarily due to the acquisition of the New England Gas System, the acquisition of the Peach State Gas System, the new rates for Granite State Electric System, and higher gas consumption.

For the nine months ended September 30, 2014, the Liberty Utilities (East) region's revenue from utility electricity sales totalled U.S. $84.3 million, as compared to U.S. $63.5 million during the same period in 2013, an increase of U.S. $20.8 million, or 32.8%. For the nine months ended September 30, 2014, electricity purchases for the Liberty Utilities (East) region totalled U.S. $51.7 million, as compared to U.S. $41.2 million during the same period in 2013. Net utility sales from the electric utility for the nine months ended September 30, 2014 were U.S. $32.6 million, as compared to U.S. $22.3 million during the same period in 2013, an increase of U.S. $10.3 million. The increase in net utility electricity sales can be attributed to an increase in distribution rates to customers resulting from the implementation of final rates from the Granite State Electric System general rate case, as well as U.S. $2.5 million in additional revenue representing the difference between the interim rates previously granted and the final rates retroactive to July 1, 2013.

For the nine months ended September 30, 2014, the Liberty Utilities (East) region's revenue from natural gas sales and distribution totalled U.S. $218.0 million, as compared to U.S. $101.8 million during the same period in 2013, an increase of U.S. $116.2 million. For the nine months ended September 30, 2014, natural gas purchases totalled U.S. $133.2 million, as compared to U.S $60.0 million during the same period in 2013. Net utility sales from the natural gas utilities excluding transportation were U.S. $84.8 million as compared to U.S. $41.8 million, an increase of U.S. $43.0 million compared to the same period in 2013. The increase in net utility sales from the natural gas utilities is attributed as follows: U.S. $4.8 million increase from the EnergyNorth Gas System due to below seasonal temperatures experienced during the first quarter of 2014, as compared to the first quarter of 2013; U.S. $12.0 million increase from the Peach State Gas System, which was acquired on April 1, 2013; and U.S. $26.2 million increase from the New England Gas System, which was acquired on December 20, 2013.

For the nine months ended September 30, 2014, the Liberty Utilities (East) region's revenue from gas transportation sales totalled U.S. $14.1 million, as compared to U.S. $9.9 million during the same period in 2013, an increase of U.S. $4.2 million. During the nine months ended September 30, 2014, the EnergyNorth Gas System contributed U.S. $7.6 million, the Peach State Gas System contributed U.S. $1.6 million, and the New England Gas System contributed U.S. $4.9 million.

For the nine months ended September 30, 2014, operating expenses, excluding electricity and natural gas purchases, totalled U.S. $75.5 million, as compared to U.S. $46.9 million during the same period in 2013, an increase of U.S. $28.6 million. The increase in operating expenses, as compared to the same period in 2013, can be primarily attributed to the acquisitions of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013.

For the nine months ended September 30, 2014, other income for the Liberty Utilities (East) region totaled U.S. $0.9 million, and primarily consists of an equity allowance for funds utilized during construction and rental income.

For the nine months ended September 30, 2014, the Liberty Utilities (East) region's operating profit totalled U.S. $58.9 million, as compared to U.S. $28.1 million during the same period in 2013, an increase of U.S. $30.8 million.

Measured in Canadian dollars, the Liberty Utilities (East) region's operating profit was $64.9 million, as compared to $28.7 million during the same period in 2013, an increase of $36.2 million.

	Three months ended September 30,	
	2014	**2013**
Average Active Natural Gas Connections For The Period		
Residential	175,200	127,600
Commercial and Industrial	17,200	13,300
Total Average Active Natural Gas Connections For The Period	**192,400**	**140,900**
Average Active Electric Connections For The Period		
Residential	37,200	36,800
Commercial and Industrial	6,500	6,500
Total Average Active Electric Connections For The Period	**43,700**	**43,300**
Customer Usage (GW-hrs)		
Residential	71.6	83.1
Commercial and Industrial	201.8	184.3
Total Customer Usage (GW-hrs)	**273.4**	**267.4**
Customer Usage (MMBTU)		
Residential	794,000	571,200
Commercial and Industrial	900,000	813,500
Total Customer Usage (MMBTU)	**1,694,000**	**1,384,700**

For the three months ended September 30, 2014, the Liberty Utilities (East) region's electricity usage totalled 273.4 GW-hrs and natural gas usage totalled 1,694,000 MMBTU, as compared to 267.4 GW-hrs and 1,384,700 MMBTU during the same period in 2013. The New England Gas System usage totalled 354,000 MMBTU.

2014 Third Quarter Operating Results

	Three months ended September 30,		Three months ended September 30,	
	2014 U.S. $ (millions)	2013 U.S. $ (millions)	**2014 Can $ (millions)**	2013 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 27.0**	$ 23.5	**$ 29.4**	$ 24.4
Less: Cost of Sales – Electricity	**(16.4)**	(14.4)	**(17.9)**	(15.0)
Net Utility Sales - Electricity	**$ 10.6**	$ 9.1	**$ 11.5**	$ 9.4
Utility natural gas sales and distribution	**$ 28.7**	$ 17.5	**$ 31.3**	$ 18.0
Less: Cost of Sales – Natural Gas[1]	**(10.6)**	(4.7)	**(11.5)**	(4.8)
Net Utility Sales - Natural Gas	**$ 18.1**	$ 12.8	**$ 19.8**	$ 13.2
Gas transportation	**2.7**	1.9	**2.9**	2.0
Other revenue	**0.7**	—	**0.8**	—
Net Utility Sales	**$ 32.1**	$ 23.8	**$ 35.0**	$ 24.6
Expenses				
Operating expenses	**(24.5)**	(17.8)	**(26.4)**	(18.4)
Other income	**0.2**	(0.3)	**0.3**	(0.3)
Division operating profit	**$ 7.8**	$ 5.7	**$ 8.9**	$ 5.9

1 Natural Gas costs are shown net of U.S. $5.8 million of gas deferral debits due to under-collection of gas commodity costs in the quarter.

The cost of electricity and natural gas is passed through to the Liberty Utilities (East) region's customers. As a result, the division compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the three months ended September 30, 2014, net utility sales for the Liberty Utilities (East) region totalled U.S. $32.1 million, as compared to U.S. $23.8 million during the same period in 2013, an increase of U.S.$8.3 million. The increase was primarily due to higher rates for the Granite State Electric System and the acquisition of the New England Gas System on December 20, 2013.

For the three months ended September 30, 2014, the Liberty Utilities (East) region's revenue from utility electricity sales totalled U.S. $27.0 million, as compared to U.S. $23.5 million during the same period in 2013, an increase of U.S.$3.5 million, or 14.9%. For the three months ended September 30, 2014, electricity purchases for the Liberty Utilities (East) region totalled U.S. $16.4 million, as compared to U.S. $14.4 million during the same period in 2013. Net utility sales from the electric utility were U.S. $10.6 million as compared to U.S.$9.1 million, an increase of U.S.$1.5 million as compared to the same period in 2013. The increase in net utility electricity sales can be primarily attributed to increased distribution rates to customers as a result of the implementation of the final rates from the Granite State Electric System's general rate case.

For the three months ended September 30, 2014, the Liberty Utilities (East) region's revenue from natural gas sales and distribution totalled U.S. $28.7 million, as compared to U.S. $17.5 million during the same period in 2013, an increase of U.S. $11.2 million. For the three months ended September 30, 2014, natural gas purchases totalled U.S. $10.6 million, as compared to U.S.$4.7 million for the same period in 2013. Net utility sales from the natural gas utilities excluding transportation were U.S. $18.1 million as compared to U.S. $12.8 million, an increase of U.S. $5.3 million during the same period in 2013. The increase in net utility sales from the natural gas utilities is attributed as follows: U.S. $0.1 million increase as a result of increased customer demand at the EnergyNorth Gas System; U.S. $0.8 million primarily as a result of the GRAM filing at the Peach State Gas System; and U.S. $4.5 million from the New England Gas System, which was acquired on December 20, 2013.

For the three months ended September 30, 2014, the Liberty Utilities (East) region's revenue from gas transportation sales totalled U.S. $2.7 million, as compared to U.S. $1.9 million during the same period in 2013, an increase of U.S. $0.8 million. During the three months ended September 30, 2014, the EnergyNorth Gas System contributed U.S. $1.2 million, the Peach State Gas System contributed U.S. $0.5 million, and the New England Gas System contributed U.S. 1.0 million.

For the three months ended September 30, 2014, operating expenses, excluding electricity and natural gas purchases, totalled U.S. $24.5 million, as compared to U.S. $17.8 million during the same period in 2013, an increase of U.S. $6.7 million. The increase in operating expenses as compared to the same period in 2013 can be primarily attributed to the acquisition of the New England Gas System on December 20, 2013.

For the three months ended September 30, 2014, other income for the Liberty Utilities (East) region totaled U.S. $0.2 million, and primarily consists of an equity allowance for funds utilized during construction and rental income.

For the three months ended September 30, 2014, the Liberty Utilities (East) region's operating profit totalled U.S. $7.8 million, as compared to $5.7 million during the same period in the prior year.

Measured in Canadian dollars, the Liberty Utilities (East) region's operating profit was $8.9 million, as compared to $5.9 million during the same period in 2013, an increase of $3.0 million.

Regulatory Proceedings

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

Utility	State	Regulatory Proceeding Type	Rate Request	Current Status
Peach State Gas System	Georgia	Georgia Rate Adjustment Mechanism ("GRAM") filing	U.S. $3.9 million	Application filed on October 1, 2014 requesting new rates to come into effect February 1, 2015.
Missouri Gas System	Missouri	General Rate Case	U.S. $7.6 million	Order expected in Q1 2015.
Illinois Gas System	Illinois	General Rate Case	U.S. $5.7 million	Order expected in Q1 2015.
Pine Bluff Water System	Arkansas	General Rate Case	U.S. $2.5 million	Application was filed on July 2, 2014; Order expected in Q2 2015
EnergyNorth System	New Hampshire	General Rate Case	U.S. $16.1 million	Application filed August 1, 2014; Order expected in Q3 2015

On October 1, 2014, the Peach State Gas System filed an application for an increase in revenue of U.S. $3.9 million in its annual GRAM filing with the GPSC. New rates would be effective February 1, 2015 for the period February 1, 2015 through January 31, 2016 to reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 30 (Historic Test Year) with adjustments for the 12 months ending August 31, 2015 (Forward Looking Test Year). Commission approval is expected in Q1 2015.

In the first quarter of 2014, the Midstates Gas System filed a rate case with the Missouri Public Service Commission ("MOPSC") seeking an increase in revenue of U.S. $7.6 million, consisting of $6.3 million in new, incremental revenue and $1.3 million through the ISRS surcharge (infrastructure system replacement surcharge). The filing is based on a test year ending September 30, 2013, with revenues, expenses and rate bases adjusted to reflect known and measurable changes through April 30, 2014. The case is expected to conclude in first quarter of 2015.

Late in the first quarter of 2014, the Midstates Gas System filed a rate case with the Illinois Commerce Commission ("ICC") seeking an increase in revenue of U.S. $5.7 million. The filing is based on a test year that includes anticipated capital expenditures within 2014 and 2015. The case is expected to conclude in the first quarter of 2015.

Pine Bluff Water System filed an application on July 2, 2014 with the Arkansas Public Service Commission ("APSC") seeking an increase in revenue of U.S. $2.5 million based on a test year ending January 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The previous test year ended September 30, 2009. An Order and new rates are expected in the second quarter of 2015.

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%. The application includes a revenue decoupling proposal and seeks recovery of capital costs related to the conversion of the system to Liberty Utilities ownership. Expected implementation of the new rates is in the third quarter of 2015.

Corporate and Other Expenses

	Three months ended September 30,		Nine months ended September 30,	
	2014 (millions)	2013 (millions)	**2014 (millions)**	**2013 (millions)**
Corporate and other expenses:				
Administrative expenses[1]	**$ 8.2**	$ 6.2	**$ 24.2**	$ 18.4
(Gain)/Loss on foreign exchange	**(0.5)**	0.9	**(1.4)**	(0.4)
Interest expense	**15.9**	13.9	**48.3**	39.0
Interest, dividend and other Income	**(0.7)**	(0.5)	**(2.7)**	(1.8)
Write down on note receivable and long-term investments	7.2	—	8.2	—
Write down of Property Plant and Equipment	—	—	—	—
Acquisition-related costs	**0.4**	0.5	**0.9**	1.5
(Gain)/Loss on derivative financial instruments	**(1.6)**	(0.6)	**(0.7)**	(2.5)
Income tax expense/(recovery)	**(4.5)**	(3.2)	**13.1**	4.0

[1] Administrative expenses relates to costs for APUC, APCO, and Liberty Utilities.

2014 NINE MONTH CORPORATE AND OTHER EXPENSES

During the nine months ended September 30, 2014, administrative expenses totalled $24.2 million, as compared to $18.4 million in the same period in 2013. The expense increase for the period is primarily due to approximately $4.9 million of expenses previously classified as direct operating expenses that have been reclassified in 2014 as administrative expenses, as certain functions are now being performed centrally as part of a shared services function across the entire company.

For the nine months ended September 30, 2014, interest expense totalled $48.3 million, as compared to $39.0 million in the same period in 2013. The increased interest expense is a result of new indebtedness incurred in the latter part of 2013 and first quarter of 2014 used to finance the new acquisitions and other growth initiatives.

For the nine months ended September 30, 2014, interest, dividend and other income totalled $2.7 million, as compared to $1.8 million in the same period in 2013. Interest, dividend and other income primarily consists of rental income and dividends from APUC's share investment in the Kirkland and Cochrane Thermal Facilities.

For the nine months ended September 30, 2014, gains on derivative financial instruments totalled $0.7 million, as compared to a gain of $2.5 million in the same period in 2013. The change was primarily driven by decreased gains on hedges to purchase electricity for resale at contracted rates that differ from the market rate.

An income tax expense of $13.1 million was recorded in the nine months ended September 30, 2014, as compared to an expense of $4.0 million during the same period in 2013. The income tax expense for the nine months ended September 30, 2014 primarily increased due to higher earnings from operations, increased deferred taxes on HLBV income, investment write-downs, a stronger U.S. dollar, and other items permanently non-deductible for tax purposes.

2014 THIRD QUARTER CORPORATE AND OTHER EXPENSES

During the quarter ended September 30, 2014, administrative expenses totalled $8.2 million, as compared to $6.2 million in the same period in 2013. The expense increase for the quarter is primarily due to administrative expenses, as certain functions are now being performed centrally as part of a shared services function across the entire company.

For the quarter ended September 30, 2014, interest expense totalled $15.9 million, as compared to $13.9 million in the same period in 2013. The increased interest expense is a result of new indebtedness incurred in the latter part of 2013 and first quarter of 2014 used to finance the new acquisitions and other growth initiatives.

For the quarter ended September 30, 2014, interest, dividend and other income totalled $0.7 million, as compared to $0.5 million in the same period in 2013. Interest, dividend and other income primarily consists of rental income and dividends from APUC's share investment in the Kirkland and Cochrane Thermal Facilities.

For the quarter ended September 30, 2014, losses on derivative financial instruments totalled $1.6 million, as compared to gains of $0.6 million in the same period in 2013. The change was primarily driven by increased gains on hedges to purchase electricity for resale at contracted rates that differ from the market rate.

An income tax recovery of $4.5 million was recorded in the three months ended September 30, 2014, as compared to an income tax recovery of $3.2 million during the same period in 2013. The increase in income tax recovery for the three months ended September 30, 2014 is primarily due to higher earnings from operations, investment write-downs, 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 audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

	Three months ended September 30,		Nine months ended September 30,	
	2014 (millions)	2013 (millions)	**2014 (millions)**	2013 (millions)
Net earnings attributable to Shareholders	**$ (6.3)**	$ 6.0	**$ 44.1**	$ 7.1
Add (deduct):				
Net earnings / (loss) attributable to the non-controlling interest, exclusive of HLBV	**0.3**	(0.9)	**4.5**	6.2
(Earnings) / loss from discontinued operations	**0.2**	0.3	**0.6**	35.3
Income tax expense / (recovery)	**(4.5)**	(3.2)	**13.1**	4.0
Interest expense	**15.9**	13.9	**48.3**	39.0
Gain on sale of assets	**—**	0.1	**(0.3)**	0.1
Non-cash write downs	**7.2**	—	**8.2**	—
Acquisition costs	**0.4**	0.5	**0.9**	1.5
(Gain)/Loss on derivative financial instruments	**(1.6)**	(0.6)	**(0.7)**	(2.5)
Realized Gain on Energy Derivative Contracts	**(0.2)**	(0.5)	**3.8**	0.2
(Gain)/Loss on foreign exchange	**(0.5)**	0.9	**(1.4)**	(0.4)
Depreciation and amortization	**30.5**	23.7	**85.1**	69.1
Adjusted EBITDA	**$ 41.4**	$ 40.2	**$ 206.2**	$ 159.6

Hypothetical Liquidation at Book Value ("HLBV") represents the value of net tax attributes earned by APCo 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 nine months ended September 30, 2014 amounted to approximately $2.3 million and $18.3 million, respectively.

For the nine months ended September 30, 2014, Adjusted EBITDA totalled $206.2 million, as compared to $159.6 million in the same period in 2013, an increase of $46.6 million. For the quarter ended September 30, 2014, Adjusted EBITDA totalled $41.4 million, as compared to $40.2 million in the same period in 2013, an increase of $1.2 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.

	Three months ended September 30 (millions)		Nine months ended September 30 (millions)	
Comparative Prior Period Adjusted EBITDA	$	40.2	$	159.6
Significant Changes:				
Liberty Utilities:				
Increased delivery and treatment of water and wastewater at the Liberty Utilities (West) region		0.4		2.4
Increased rates at the Granite State Electric System offset by lower customer demand		0.8		8.6
Changes in customer demand and higher operating expenses at the EnergyNorth and the Midstates Gas Systems		(0.1)		0.1
2013 Acquisition of the New England and Peach State Gas Systems		0.7		23.2
APCo:				
Renewable:				
Decreased hydrology resource		(3.0)		(4.2)
Decreased/increased wind resources for the quarter/year to date, at the U.S. Wind Facilities offset by unfavorable periodic hedge settlements shortfalls at the Minonk, Sandy Ridge and Senate facilities		(0.6)		(0.4)
Higher realized prices on sale of Renewable Energy Credits		0.4		4.6
Start of commercial operations for the Cornwall Solar Facility		2.0		4.5
Increased wind resources at the St Leon wind facilities		1.1		2.8
Unfavorable retail pricing at AES partially offset by gains from hedge settlements and increased customer load.		(0.6)		(2.2)
Thermal:				
Increased market prices at the Sanger Thermal Facility		0.4		0.7
Administrative expense		(2.0)		(5.8)
Increased results from the stronger U.S. dollar		1.5		11.9
Other		0.2		0.4
Current Period Adjusted EBITDA	**$**	**41.4**	**$**	**206.2**

Reconciliation of adjusted net earnings to net earnings

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

The following table shows the reconciliation of net earnings to adjusted net earnings exclusive of these items:

	Three months ended September 30,		Nine months ended September 30,	
	2014 (millions)	2013 (millions)	**2014 (millions)**	2013 (millions)
Net earnings attributable to Shareholders	**$ (6.3)**	$ 6.0	**$ 44.1**	$ 7.1
Add (deduct):				
(Gain) / Loss from discontinued operations, net of tax	**0.2**	0.3	**0.6**	35.3
(Gain)/Loss on derivative financial instruments, net of tax	**(1.0)**	(0.3)	**(0.4)**	(1.5)
Realized Gain/(Loss) on derivative instruments, net of tax	**(0.5)**	(0.7)	**1.2**	(1.0)
(Gain)/Loss on foreign exchange, net of tax	**(0.3)**	0.5	**(0.9)**	(0.3)
Write down on note receivable and long-term investments	**7.2**	—	**8.2**	—
Gain on asset disposal, net of tax	**—**	0.1	**(0.2)**	0.1
Acquisition costs, net of tax	**0.3**	0.3	**0.6**	0.9
Adjusted net earnings/(loss)	**$ (0.4)**	$ 6.2	**$ 53.2**	$ 40.6
Adjusted net earnings/(loss) per share	**$ (0.01)**	$ 0.02	**$ 0.22**	$ 0.18

For the nine months ended September 30, 2014, adjusted net earnings totalled $53.2 million, as compared to adjusted net earnings of $40.6 million in the same period in 2013, an increase of $12.6 million. The increase in adjusted net earnings for the nine months ended September 30, 2014 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense, and higher interest expense as compared to the same period in 2013.

For the three months ended September 30, 2014, adjusted net loss totalled $0.4 million, as compared to adjusted net earnings of $6.2 million in the same period in 2013, a decrease of $6.6 million. The decrease in adjusted net earnings for the three months ended September 30, 2014 is primarily due to decreased earnings from operations, higher depreciation and amortization expense, and higher interest expense as compared to the same period in 2013.

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 audited Consolidated Statement of Operations and Statement of Cash Flows. This supplementary disclosure is intended to more fully explain disclosures related to adjusted funds from operations and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to funds from operations in accordance with GAAP.

The following table shows the reconciliation of funds from operations to adjusted funds from operations exclusive of these items:

	Three months ended September 30,		Nine months ended September 30,	
	2014 (millions)	**2013 (millions)**	**2014 (millions)**	**2013 (millions)**
Cash flows from operating activities	**$ (3.1)**	$ 14.9	**$ 96.3**	$ 70.5
Add (deduct):				
Changes in non-cash operating items	**21.1**	6.1	**33.6**	34.2
Cash (provided)/used in discontinued operation	**0.3**	1.0	**0.8**	0.9
Production Tax Credits received from non-controlling interests	**—**	—	**9.0**	—
Acquisition costs	**0.4**	0.5	**0.9**	1.5
Adjusted funds from operations	**$ 18.7**	$ 22.5	**$ 140.6**	$ 107.1
Adjusted funds from operations per share	**$ 0.08**	$ 0.10	**$ 0.64**	$ 0.51

For the nine months ended September 30, 2014, adjusted funds from operations totalled $140.6 million, as compared to adjusted funds from operations of $107.1 million in the same period in 2013, an increase of $33.5 million.

For the three months ended September 30, 2014, adjusted funds from operations totalled $18.7 million, as compared to adjusted funds from operations of $22.5 million in the same period in 2013, a decrease of $3.8 million.

SUMMARY OF PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

	Three months ended September 30,		Nine months ended September 30,	
	2014 (millions)	2013 (millions)	**2014 (millions)**	**2013 (millions)**
APCo:				
Renewable	**$ 61.5**	$ 17.1	**$ 137.4**	$ 29.1
Thermal	**0.5**	—	**3.5**	0.3
Total APCo	**$ 62.0**	$ 17.1	**$ 140.9**	**$ 29.4**
LIBERTY UTILITIES				
West	**8.7**	6.7	**18.3**	10.4
Central	**7.9**	6.7	**21.4**	20.3
East	**28.4**	9.3	**59.8**	35.0
Total Liberty Utilities	**$ 45.0**	$ 22.7	**$ 99.5**	**$ 65.7**
Corporate	**4.3**	—	**50.2**	0.7
Total	**$ 111.3**	$ 39.8	**$ 290.6**	**$ 95.8**

The company's consolidated capital expenditure plan for 2014 is estimated to be approximately $415.4 million. APCo expects to invest approximately $48.1 million throughout the remainder of the fiscal year primarily in connection with the development of its existing project portfolio. Liberty Utilities expects to invest approximately $76.7 million throughout the remainder of the fiscal year primarily to improve the reliability and efficiency of its gas, and electric utility distribution systems.

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

2014 Nine Month Property Plant and Equipment Expenditures

During the nine months ended September 30, 2014, APCo incurred capital expenditures of $140.9 million, as compared to $29.4 million during the comparable period in 2013. During the nine months ended September 30, 2014, APCo's Renewable Energy Division spent $137.4 million in capital expenditures, as compared to $29.1 million in the comparable period in 2013. The increase is primarily due to turbine contract payments related to the Morse Wind Project, completion of construction of the Cornwall Solar Project, and costs related to the St. Damase Wind and the Bakersfield Solar Projects. APCo's Thermal Energy Division net capital expenditures were $3.5 million, as compared to $0.3 million in the comparable period in 2013. The Thermal Division's capital expenditures primarily consist of $0.8 million at the Windsor Locks Thermal Facility and $2.5 million at the Sanger Thermal Facility largely related to the LM6000 hot section overhaul.

During the nine months ended September 30, 2014, Liberty Utilities invested $99.5 million in capital expenditures, as compared to $65.7 million during the comparable period in 2013. The Liberty Utilities (West) region's $18.3 million in capital expenditures primarily related to improvement and replenishment at the CalPeco Electric System. The Liberty Utilities (Central) region's $21.4 million in capital expenditures was primarily related to improvement and replenishment of pipe and related facilities. The Liberty Utilities (East) region's $59.8 million in capital expenditures was primarily related to: (i) completion of a second supply line, reliability enhancements, new business projects, leak prone pipe replacements, and pipeline corrosion protection systems on the EnergyNorth Gas System, (ii) the implementation of a new IT system on the Granite State Electric and EnergyNorth Gas Systems, and (iii) growth and system upgrades at the Peach State Gas System.

2014 Third Quarter Property Plant and Equipment Expenditures

During the three months ended September 30, 2014, APCo incurred capital expenditures of $62.0 million, as compared to $17.1 million during the comparable period in 2013. During the three months ended September 30, 2014, APCo's Renewable Energy Division spent $61.5 million in capital expenditures, as compared to $17.1 million in the comparable period in 2013. The increase is primarily due to turbine contract payments related to the Morse Wind Project and costs related to the St. Damase Wind and the Bakersfield Solar Projects. APCo's Thermal Energy Division net capital expenditures were $0.5 million, as compared to nil in the comparable period in 2013. The Thermal Division's capital expenditures consist of $0.3 million relating to the Windsor Locks Thermal Facility and $0.2 million relating to the Sanger Thermal Facility.

During the three months ended September 30, 2014, Liberty Utilities invested $45.0 million in capital expenditures, as compared to $22.7 million during the comparable period in 2013. The Liberty Utilities (West) region's $8.7 million in capital expenditures are primarily related to improvement and replenishment at the CalPeco Electric System. The Liberty Utilities (Central) region's $7.9 million in capital expenditures was primarily related to improvement and replenishment of pipe and related facilities. The Liberty Utilities (East) region's $28.4 million in capital expenditures was primarily related to: (i) completion of reliability enhancements, new business projects, and vehicle purchases at the Granite State Electric System, (ii) growth projects, leak prone pipe replacements, and pipeline corrosion protection systems at the EnergyNorth Gas System, and (iii) growth and system upgrades at the Peach State Gas System.

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C93), APCo 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 one facility.

APCo currently estimates further capital expenditures of approximately $7.3 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:

	Total	2014	2015	2016	2017
Future Estimated Bill C-93 Capital Expenditures	$ 7.3	0.5	3.5	3.0	0.3

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

On May 18, 2014, the Donnacona Hydro Facility experienced ice damage during the spring thaw and has been shut down. APCo had previously planned Capital Expenditures for Donnacona in 2015 and 2016 in the amount of $7.8 million. APCo is evaluating if any of the structure can be salvaged, whether an entire re-build is required, and what amounts are recoverable from its insurers.

In addition to the C-93 related dam remediation work, APCo has implemented a dam condition monitoring program at some of the above facilities following recommendations specified in the dam safety reviews.

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving operating facilities available at APUC, APCo and Liberty Utilities to manage the liquidity and working capital requirements of each division (collectively the "Credit Facilities").

Bank Credit Facilities

The following table sets out the amounts drawn, letters of credit issued, and outstanding amounts available to APUC and its subsidiaries as at September 30, 2014 under the Credit Facilities:

	As at September 30, 2014				As at Dec 31 2013
	APUC (millions)	APCo (millions)	Liberty Utilities (millions)	Total (millions)	Total (millions)
Committed Credit Facilities	$ 65.0	$ 350.0	$ 224.0	$ 639.0	$ 477.7
Funds drawn on the Credit Facilities	—	(53.8)	(126.2)	(180.0)	(210.2)
Letters of Credit issued	(10.5)	(55.6)	(9.0)	(75.1)	(64.9)
Funds available for draws on the Credit Facilities	**$ 54.5**	**$ 240.6**	**$ 88.8**	**$ 383.9**	**$ 202.6**
Cash on Hand				26.6	13.8
Total liquidity and capital reserves	**$ 54.5**	**$ 240.6**	**$ 88.8**	**$ 410.5**	**$ 216.4**

As at September 30, 2014, the APUC $65.0 million senior unsecured revolving credit facility (the "APUC Credit Facility") was undrawn and had $10.5 million of outstanding letters of credit.

As at September 30, 2014, the APCo $350.0 million senior unsecured revolving credit facility (the "APCo Credit Facility") had drawn $53.8 million and had $55.6 million in outstanding letters of credit.

As at September 30, 2014, the Liberty Utilities $224.0 million (U.S. $200.0 million) senior unsecured revolving credit facility (the "Liberty Credit Facility") had drawn $126.2 million and had $9.0 million of outstanding letters of credit.

On July 31, 2014, APCo increased the credit available under the APCo Credit Facility to $350 million from $200 million. The larger credit facility will be used to provide additional liquidity in support of APCo's $1,243.3 million development portfolio to be completed over the next three years. In addition to the larger size, the maturity of the credit facility has been extended from three to four years extending to July 31, 2018.

As at September 30, 2014, the weighted average tenor of APUC's total long term debt is approximately 8 years with an average interest rate of 4.9%.

Contractual Obligations

Information concerning contractual obligations as of September 30, 2014 is shown below:

		Total (millions)		Due less than 1 year (millions)		Due 1 to 3 years (millions)		Due 4 to 5 years (millions)		Due after 5 years (millions)
Long-term debt obligations	$	1,413.4		8.8		69.9		199.5		1,135.2
Advances in aid of construction	$	78.3		1.3		—		—		77.0
Interest on long-term debt obligations	$	452.1		64.2		126.2		104.8		156.9
Purchase obligations	$	157.4		157.4		—		—		—
Environmental Obligations	$	72.0		3.0		52.0		6.1		10.9
Derivative financial instruments:										
Cross Currency Swap	$	20.1		0.8		1.6		1.2		16.5
Interest rate swap	$	1.9		1.9		—		—		—
Energy derivative contracts	$	0.2		0.2		—		—		—
Commodity Contracts	$	1.2		1.0		0.2		—		—
Capital lease obligations	$	—		—		—		—		—
Capital projects	$	129.7		116.4		13.3		—		—
Long term service agreements	$	228.4		52.3		61.5		44.4		70.2
Purchased power	$	613.0		24.4		60.4		58.6		469.6
Gas delivery, service and supply agreements	$	32.5		32.5		—		—		—
Operating leases	$	108.2		5.5		8.9		7.5		86.3
Other obligations	$	34.1		8.6		—		—		25.5
Total obligations	**$**	**3,342.5**	**$**	**478.3**	**$**	**394.0**	**$**	**422.1**	**$**	**2,048.1**

Equity

The shares of APUC are publicly traded on the Toronto Stock Exchange. As at September 30, 2014, APUC had 227,406,479 common shares issued and outstanding.

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

On September 16, 2014, APUC completed the Offering of 16,860,000 common shares at a price of $8.90 per share, for gross proceeds of approximately $150.0 million. On September 26, 2014, the underwriters exercised the over-allotment option granted with the Offering and an additional 2,529,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued 19,389,000 common shares under the Offering for the total gross proceeds of approximately $172.6 million.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at September 30, 2014, APUC had outstanding:

- 4,800,000 cumulative rate reset preferred shares, Series A (the "Series A Shares"), yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C preferred shares (the "Series C 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 preferred shares, Series D (the "Series D 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 shareholders of APUC. As at September 30, 2014, there were 56.6 million common shares representing approximately 25% of total shares outstanding that had been registered with the Reinvestment Plan. During the three and nine months ended September 30, 2014, there were 514,289 and 1,095,895 common shares, respectively, issued under the Reinvestment Plan. Subsequent to the end of the quarter, on October 15, 2014, 665,172 common shares were issued under the Reinvestment Plan.

Emera ownership

On September 4, 2014, APUC and Emera Inc. ("Emera") entered into a subscription agreement pursuant to which Emera agreed to subscribe for an aggregate of 7,865,170 subscription receipts ("Subscription Receipts") of APUC at a price of $8.90 per Subscription Receipt, for a subscription price of $70.0 million. On September 26, 2014, as a result of the Underwriters exercising the Over-Allotment Option, an additional 843,000 Subscription Receipts were issued to Emera at a price of $8.90 per Subscription Receipt for a subscription price of $7.5 million, and an aggregate subscription price of $77.5 million.

The proceeds of the Subscription Receipt private placement are intended to be used to partially finance the Odell Wind Project (described below).

The completion of the Subscription Receipt private placement occurred on October 7, 2014. At any time after the closing of the Odell Acquisition, Emera may elect to convert the Subscription Receipts for no additional consideration on a one-for-one basis into Shares, subject to Emera (i) not holding, at any time after conversion of Subscription Receipts, more than 25% of the outstanding Common Shares of APUC and (ii) having received all necessary regulatory approvals for acquiring additional Common Shares of APUC. In the event that Emera has not elected to convert the Subscription Receipts by the second anniversary of the closing of the Odell Acquisition, they will automatically convert into Common Shares.

In the event that (i) the Offering does not close or (ii) the acquisition of the Odell Wind Project is terminated, the subscription agreement with Emera will be terminated. In that event, the Subscription Receipts will be returned to APUC for cancellation and the aggregate subscription price for the Subscription Receipts will be repaid to Emera.

As at November 13, 2014, Emera owns 50.1 million APUC common shares, representing approximately 22.0% of the total outstanding common shares of the Company.

SHARE BASED COMPENSATION PLANS

For the three and nine months ended September 30, 2014, APUC recorded $1.1 million and $2.1 million, respectively, in total share-based compensation expense, as compared to $0.6 million and $1.6 million, respectively, for the same period in 2013. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at September 30, 2014, total unrecognized compensation costs related to non-vested options and share unit awards were $2.7 million and $2.6 million, respectively, and are expected to be each recognized over a period of 1.8 years .

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.

As at September 30, 2014, APUC had 5,537,127 options issued and outstanding. 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.

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.

During the quarter, the Company settled 22,665 vested PSUs for $0.2 million in cash. 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. During the quarter, the Company issued 386,071 PSUs to executives and employees of the Company.

As at September 30, 2014, a total of 423,491 PSU's have 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. During the quarter, the Company issued 8,597 DSUs to the directors of the Company.

As at September 30, 2014, a total of 102,087 DSUs had been granted under the DSU plan.

Employee Share Purchase Plan

APUC has an employee share purchase plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the quarter, the Company issued 48,038 shares under the ESPP.

As at September 30, 2014, a total of 217,594 shares had been issued under the ESPP.

RELATED PARTY TRANSACTIONS

A member of the Board of Directors of APUC is an executive at Emera . For the three and nine months ended September 30, 2014, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $1,497 and U.S. $3,012, respectively (2013 - U.S. $1,466 and U.S, $4,628). For the three and nine months ended September 30, 2014, Liberty Utilities purchased natural gas amounting to U.S. $149 and U.S. $4,891 (2013 - U.S. $38 and U.S. $750) 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.

Ian Robertson and Chris Jarratt ("Senior Executives"), Chief Executive Officer and Vice-Chair of APUC respectively, partially own an entity from which APUC leases its head office facilities. Base lease costs for the three and nine months ended September 30, 2014 were $78 and $236, respectively (2013 - $84 and $252). Subsequent to quarter end, APUC completed moving all head office employees into the new premises and has entered into a lease termination agreement with respect to the former head office facilities leased from an entity partially owned by Senior Executives. The lease termination agreement is for nominal consideration and is subject to the completion of a sale of the property to a third party pursuant to an agreement of purchase and sale which is expected to close before the end of 2014. Subsequent to the sale, there will be no further related party matter in relation to an office lease.

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

TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. 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.

Market price risk

Liberty Utilities is not exposed to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

APCo has certain market price risk exposures and takes steps to mitigate those risks.

On May 15, 2012, APCo 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 U.S. $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of U.S. $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. APCo mitigates this risk exposure by entering into hedge quantities for less than 100% of the long term average expected production, thereby reducing the risk of not producing the minimum hedge quantities.

APCo entered into unit contingent financial hedges, which commenced January 1, 2014 for a one year period. These hedges are structured to hedge the production from the Sandy Ridge, Senate and Minonk Wind facilities in excess of the quantities covered under the hedges, which commenced on January 1, 2013. The unit contingent hedges do not have a minimum volume commitment and hence the facilities do not bear any market risk associated with production. As a result, these wind facilities now have hedges in place covering 100% of the energy produced.

In addition to the above noted hedges, from time to time APCo 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 APUC Credit Facility had no amounts outstanding as at September 30, 2014. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The APCo Credit Facility had $53.8 million outstanding as at September 30, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.5 million annually.
- APCo's project debt at its Sanger Thermal Facility has a balance of $21.5 million as at September 30, 2014. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Shady Oaks Senior Debt Facility had $88.5 million outstanding as at September 30, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.9 million annually.
- The Liberty Credit Facility had $126.2 million outstanding as at September 30, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.3 million annually.

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

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 APCo and Liberty Utilities 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 at each of APCo and Liberty Utilities to meet their liabilities when due.

As at September 30, 2014, APUC and its subsidiaries had a combined $383.9 million of committed and available credit facilities remaining and $26.6 million of cash resulting in $410.5 million of total liquidity and capital reserves.

APUC currently pays a dividend of U.S. $0.35 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 $1,413.5 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the credit 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 that 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.

Commodity price risk

APCO's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Utilities is exposed to energy price risk in its Liberty Utilities (West) and Liberty Utilities (East) regions. Additionally, Liberty Utilities is exposed to natural gas price risk in its Liberty Utilities (Central) and Liberty Utilities (East) regions. See APUC's audited consolidated financial statements for the years ended December 31, 2013 and 2012 for discussion of this risk.

OPERATIONAL RISK MANAGEMENT

APUC attempts to proactively manage its risk exposures in a prudent manner and has initiated a number of programs and policies such as employee health and safety programs and environmental safety programs to manage its risk exposures.

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the dependence upon APUC businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers, and environmental health and safety considerations. A further assessment of APUC's business risks is set out in the most recent AIF.

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 Second Quarter 2014 MD&A.

Trafalgar proceedings

The court has approved the sale of five of the Trafalgar facilities. The auction for the sale of the remaining two facilities is scheduled to occur in the fourth quarter of 2014.

Côte Ste-Catherine Water Lease Dues

The parties are attempting to resolve this matter through good faith negotiations.

Long Sault Global Adjustment Claim

The Application was heard in May 2014 and the parties are awaiting the judge's decision.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarters ended September 30, 2014:

Millions of dollars (except per share amounts)	4th Quarter 2013	1st Quarter 2014	2nd Quarter 2014	3rd Quarter 2014
Revenue	205.3	343.5	189.3	151.9
Adjusted EBITDA	67.6	97.5	66.4	41.4
Net earnings / (loss) attributable to shareholders from continuing operations	19.8	35.6	15.3	(6.1)
Net earnings / (loss) attributable to shareholders	13.1	35.9	14.6	(6.3)
Net earnings / (loss) per share from continuing operations	0.09	0.16	0.06	(0.04)
Net earnings / (loss) per share	0.06	0.17	0.06	(0.04)
Adjusted net earnings	18.5	36.8	16.5	(0.4)
Adjust net earnings per share	0.08	0.17	0.07	(0.01)
Total Assets	3,472.6	3,652.7	3,561.9	3,808.5
Long term debt[1]	1,255.6	1,409.4	1,389.3	1,413.5
Dividend declared per common share	0.09	0.09	0.09	0.10

	4th Quarter 2012	1st Quarter 2013	2nd Quarter 2013	3rd Quarter 2013
Revenue	138.9	193.1	148.8	127.9
Adjusted EBITDA	24.0	61.8	56.5	40.5
Net earnings / (loss) attributable to shareholders from continuing operations	6.8	20.4	15.8	6.3
Net earnings/(loss) attributable to shareholders	6.4	19.2	(18.1)	6.0
Net earnings / (loss) per share from continuing operations	0.04	0.10	0.08	0.02
Net earnings/(loss) per share	0.03	0.10	(0.09)	0.02
Adjusted net earnings	6.5	19.4	15.4	6.9
Adjust net earnings per share	0.03	0.10	0.08	0.03
Total Assets	2,779.0	2,990.7	3,201.8	3,156.4
Long term debt[1]	770.8	917.5	1,091.5	1,092.0
Dividend declared per common share	0.08	0.08	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. In addition, the company has completed a series of growth initiatives through various acquisitions in both the APCo and Liberty Utilities businesses that have positively impacted growth of APUC.

Quarterly revenues have fluctuated between $127.9 million and $343.5 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations (especially in respect of natural gas sales in the winter months), 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 $35.9 million and a net loss of $18.1 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

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 (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

During the quarter ended September 30, 2014, 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.

Management believes there has been no material changes during the three and nine months ended September 30, 2014 to the items discussed in APUC's MD&A and Note 1 of its consolidated financial statements for the year ended December 31, 2013 available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	September 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 26,601	$ 13,839
Accounts receivable, net (note 4)	125,279	160,636
Natural gas in storage	34,903	25,609
Supplies and consumables inventory	9,653	7,924
Regulatory assets (note 5)	53,466	26,125
Prepaid expenses	8,518	11,341
Notes receivable and investment (note 6)	780	598
Deferred income tax asset	14,532	19,652
Income tax receivable	399	379
Derivative instruments (note 20)	6,135	9,176
Assets held for sale (note 12(c))	1,792	23,927
	282,058	299,206
Property, plant and equipment	3,068,793	2,708,704
Intangible assets	54,221	54,416
Goodwill	89,136	84,647
Regulatory assets (note 5)	178,318	164,223
Derivative instruments (note 20)	16,548	27,123
Long-term investments and notes receivable (note 6)	31,125	32,746
Deferred income tax asset (note 3(a))	61,883	86,632
Other assets	26,407	18,784
	$ 3,808,489	$ 3,476,481

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	September 30, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 31,167	$ 14,489
Accrued liabilities	126,274	146,338
Dividends payable	22,286	17,535
Regulatory liabilities (note 5)	16,649	21,632
Long-term liabilities (note 7)	8,822	8,339
Pension and other post-employment benefits	322	305
Other long-term liabilities	8,577	7,451
Advances in aid of construction	1,304	1,239
Derivative instruments (note 20)	3,807	2,492
Environmental obligations (note 18(a)(ii))	29,691	10,111
Preferred shares series C	1,093	1,038
Income tax payable	6,302	5,159
Deferred credits	7,778	7,778
Deferred income tax liability	1,759	2,308
Liabilities held for sale (note 12)	1,300	1,471
	267,131	247,685
Long-term liabilities (note 7)	1,404,651	1,247,249
Advances in aid of construction	77,017	77,697
Regulatory liabilities (note 5)	99,929	101,657
Deferred income tax liability	150,332	137,153
Derivative instruments (note 20)	19,553	13,729
Deferred credits	14,715	17,115
Pension and other post-employment benefits	73,806	70,532
Environmental obligation (note 18(a)(ii))	41,409	59,444
Other long-term liabilities	28,231	20,492
Preferred shares Series C	17,647	17,767
	1,927,290	1,762,835
Equity:		
Preferred shares (note 9(d))	213,807	116,546
Common shares (note 9(a))	1,530,841	1,351,264
Additional paid-in capital (note 3(a))	31,780	7,313
Deficit	(508,819)	(488,406)
Accumulated other comprehensive income/(loss) (note 10)	32,206	(31,410)
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,299,815	955,307
Non-controlling interests (note 3(a))	314,253	510,654
Total Equity	1,614,068	1,465,961
Commitments and contingencies (note 18)		
Subsequent event (note 9(c))		
	$ 3,808,489	$ 3,476,481

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Revenue				
Regulated electricity sales and distribution	$ 48,868	$ 42,936	$152,264	$122,144
Regulated gas sales and distribution	42,244	28,935	321,370	167,606
Regulated water reclamation and distribution	17,193	15,852	48,215	42,726
Non-regulated energy sales	40,353	37,885	148,763	131,359
Other revenue	3,205	2,310	13,633	6,154
	151,863	127,918	684,245	469,989
Expenses				
Operating	58,102	46,701	176,799	131,361
Regulated electricity purchased	27,443	23,897	86,348	70,858
Regulated gas purchased	13,761	7,821	186,237	91,761
Non-regulated energy purchased	6,733	5,075	32,797	17,424
Administrative expenses	8,192	6,162	24,165	18,367
Depreciation of property, plant and equipment	27,611	22,547	79,325	66,015
Amortization of intangible and other assets	2,924	1,112	5,739	3,128
Loss/(gain) on foreign exchange	(491)	881	(1,422)	(437)
	144,275	114,196	589,988	398,477
Operating income from continuing operations	7,588	13,722	94,257	71,512
Interest expense	15,928	13,907	48,282	38,995
Interest, dividend income and other income	(1,683)	(1,345)	(6,237)	(5,730)
(Gain)/loss on asset disposal	—	118	(326)	118
Write down on long-lived assets (note 6)	7,180	16	8,171	16
Acquisition-related costs	448	486	945	1,500
Gain on derivative financial instruments (note 20(b)(iv))	(1,635)	(586)	(655)	(2,490)
	20,238	12,596	50,180	32,409
Earnings from continuing operations before income taxes	(12,650)	1,126	44,077	39,103
Income tax expense/(recovery) (note 15)				
Current	2,200	1,152	5,940	2,408
Deferred	(6,737)	(4,395)	7,203	1,585
	(4,537)	(3,243)	13,143	3,993
Earnings/(loss) from continuing operations	(8,113)	4,369	30,934	35,110
Loss from discontinued operations net of tax (note 12)	(214)	(300)	(646)	(35,340)
Net earnings/(loss)	(8,327)	4,069	30,288	(230)
Net loss attributable to non-controlling interests (note 14)	(2,017)	(1,954)	(13,852)	(7,372)
Net earnings/(loss) attributable to shareholders of Algonquin Power & Utilities Corp.	$ (6,310)	$ 6,023	$ 44,140	$ 7,142
Basic net earnings/(loss) per share from continuing operations (note 16)	$ (0.04)	$ 0.02	$ 0.18	$ 0.19
Basic net loss per share from discontinued operations (note 16)	—	—	—	(0.17)
Basic net earnings/(loss) per share (note 16)	(0.04)	0.02	0.18	0.02
Diluted net earnings/(loss) per share from continuing operations (note 16)	(0.04)	0.02	0.18	0.19
Diluted net loss per share from discontinued operations (note 16)	—	—	—	(0.17)
Diluted net earnings/(loss) per share (note 16)	$ (0.04)	$ 0.02	$ 0.18	$ 0.02

See accompanying notes to unaudited interim consolidated financial statements

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

(thousands of Canadian dollars)	Three months ended September 30,		Nine months ended September 30,	
	2014	**2013**	**2014**	**2013**
Net earnings/(loss)	$ (8,327)	$ 4,069	$ 30,288	$ (230)
Other comprehensive income/(loss):				
Foreign currency translation adjustment, net of tax recovery of $229 and $25 (2013 - $nil and $133), respectively (notes 20(b)(iii) and 20(c))	60,093	(24,212)	65,483	41,724
Change in fair value of cash flow hedge, net of tax of $8,499 and tax recovery of $273 (2013 - tax expense of $439 and $3,150), respectively (note 20(b)(ii))	12,474	1,355	(6,612)	10,449
Change in unrealized appreciation (depreciation) in value of available-for-sale investments	244	45	1	45
Change in unrealized pension and other post-retirement expense, net of tax of $3 and $nil (2013 - $10 and $nil), respectively (note 8)	(242)	22	(739)	45
Other comprehensive income/(loss), net of tax	72,569	(22,790)	58,133	52,263
Comprehensive income/(loss)	64,242	(18,721)	88,421	52,033
Comprehensive income/(loss) attributable to the non-controlling interests	12,927	(11,675)	4,237	15,482
Comprehensive income/(loss) attributable to shareholders of Algonquin Power & Utilities Corp.	$ 51,315	$ (7,046)	$ 84,184	$36,551

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statement of Equity
(thousands of Canadian dollars)

Nine Months ended September 30, 2014

	Common Shares	Preferred Shares	Additional paid-in capital	Accumulated Deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2013	$1,351,264	$116,546	$ 7,313	$ (488,406)	$ (31,410)	$510,654	$1,465,961
Net earnings/(loss)	—	—	—	44,140	—	(13,852)	30,288
Other comprehensive income/(loss)	—	—	—	—	40,044	18,089	58,133
Dividends declared and distributions to non-controlling interests	—	—	—	(52,706)	—	(3,818)	(56,524)
Dividends and issuance of shares under dividend reinvestment plan	11,847	—	—	(11,847)	—	—	—
Contributions received from non-controlling interests	—	—	—	—	—	8,976	8,976
Shares issued pursuant to public offering (note 9 (b))	167,210	—	—	—	—	—	167,210
Issuance of common shares under employee share purchase plan	520	—	—	—	—	—	520
Share-based compensation	—	—	2,054	—	—	—	2,054
Preferred Series D shares, net of costs (note 9(d))	—	97,261	—	—	—	—	97,261
Acquisition of non-controlling interest (notes 3(a))	—	—	22,413	—	23,572	(205,796)	(159,811)
Balance, September 30, 2014	$1,530,841	$213,807	$ 31,780	$ (508,819)	$ 32,206	$314,253	$1,614,068

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statements of Cash Flows

(thousands of Canadian dollars)	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Cash provided by (used in):				
Operating Activities:				
Net earnings/(loss) from continuing operations	$ (8,113)	$ 4,369	$ 30,934	$ 35,110
Adjustments and items not affecting cash:				
Depreciation of property, plant and equipment	27,611	22,547	79,325	66,015
Amortization of intangible assets	1,258	1,045	3,409	3,145
Other amortization	(74)	823	1,534	1,686
Deferred income taxes	(6,737)	(4,395)	7,203	1,585
Unrealized loss/(gain) on derivative financial instruments	(2,305)	(1,613)	1,659	(3,815)
Share-based compensation	1,222	562	2,054	1,541
Cost of equity funds used for construction purposes	(309)	—	(1,316)	—
Pension and post-employment benefits	(1,435)	(1,490)	(2,311)	317
Write down of long-lived assets	7,180	134	8,171	134
Changes in non-cash operating items (note 19)	(21,355)	(6,554)	(34,395)	(34,217)
Changes in non-cash operating items from discontinued operations (note 19)	261	462	770	(19)
Cash used in discontinued operations (note 12(c))	(328)	(955)	(781)	(937)
	(3,124)	14,935	96,256	70,545
Financing Activities:				
Cash dividends on common shares	(13,815)	(13,305)	(41,057)	(37,981)
Cash dividends on preferred shares	(2,600)	(1,350)	(6,903)	(4,050)
Cash contributions from non-controlling interests	—	—	8,976	—
Cash distributions to non-controlling interests	(332)	(1,328)	(3,818)	(4,409)
Issuance of common shares, net of costs	165,521	97	165,800	29,605
Issuance of preferred shares, net of costs	—	—	96,274	—
Deferred financing costs	(2,074)	(1,537)	(3,728)	(1,861)
Increase in long-term liabilities	609,051	260,633	1,283,255	653,287
Decrease in long-term liabilities	(624,571)	(244,435)	(1,169,998)	(502,498)
Increase/(decrease) in advances in aid of construction	(253)	(627)	(191)	1,850
Increase/(decrease) in other long-term liabilities	3,564	(100)	4,025	(1,157)
	134,491	(1,952)	332,635	132,786
Investing Activities:				
Increase in restricted cash	(493)	(882)	(3,053)	(1,530)
Increase in other assets	(1,169)	(200)	(1,605)	(1,983)
Distributions received in excess of equity income	188	(305)	(24)	513
Proceeds from sale of discontinued operations	—	—	20,826	22,052
Receipt of principal on notes receivable	73	123	229	326
Additions to property, plant and equipment	(111,289)	(39,875)	(290,665)	(95,660)
Acquisitions of operating entities	—	—	(8,845)	(172,189)
Acquisition of long-term investments	(1,451)	—	(12,057)	—
Proceeds from sale of investment	5,709	—	5,709	—
Acquisition of non-controlling interest (note 3(a))	—	—	(127,260)	—
	(108,432)	(41,139)	(416,745)	(248,471)
Effect of exchange rate differences on cash	294	(218)	616	1,030
Increase/(decrease) in cash and cash equivalents	23,229	(28,374)	12,762	(44,110)
Cash and cash equivalents, beginning of the period	3,372	37,386	13,839	53,122
Cash and cash equivalents, end of the period	$ 26,601	$ 9,012	$ 26,601	$ 9,012

Supplemental disclosure of cash flow information:	**2014**	**2013**	**2014**	**2013**
Cash paid during the period for interest expense	$ 23,163	$ 14,773	$ 51,519	$ 35,739
Cash paid during the period for income taxes	$ 237	$ 89	$ 1,588	$ 724
Non-cash transactions				
Property, plant and equipment acquisitions in accruals	$ 17,645	$ 15,428	$ 17,645	$ 15,428

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's principal activity is the ownership of power generation facilities and water, gas and electric utilities, through investments in securities of subsidiaries including corporations, limited partnerships and trusts which carry on these businesses.

APUC's power generation business unit conducts business under the name Algonquin Power Co. ("APCo"). APCo owns or has interests in renewable energy facilities and thermal energy facilities. APUC's Utility Services business unit conducts business under the name of Liberty Utilities Co. ("Liberty Utilities"). Liberty Utilities operates a portfolio of utilities in the United States of America providing electric, natural gas, water distribution or wastewater services.

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, 2013 except for adopted accounting policies described in note 2(a).

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. 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. 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 U.S. Financial Accounting Standards Board ("FASB") issued ASU 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This newly issued accounting standard requires an entity to present an unrecognized tax benefit, or a portion of an unrecognized tax benefit as a reduction to a deferred income tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except in some specific situations. The adoption of this standard did not have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2013-10, Derivatives and Hedging (Topic 815): Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes. This newly issued accounting standard permits the Fed Funds Effective Swap Rate (OIS) to be used as a U.S. benchmark interest rate for hedge accounting purposes under Topic 815, in addition to interest rates on direct Treasury obligations of the U.S. government and the London Interbank Offered Rate. The amendments also remove the restriction on using different benchmark rates for similar hedges. The adoption of this standard did not have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date. This newly issued accounting standard provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. The adoption of this standard did not have an impact on the Company's financial position or results of operations.

2. Recently issued accounting pronouncements (continued)

(b) Recent accounting pronouncements not yet adopted

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. This ASU is required to be applied for fiscal years and interim periods beginning after December 15, 2016 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.

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. This ASU is required to be applied prospectively for fiscal years and interim periods beginning after December 15, 2014. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

3. Business acquisitions and development projects

(a) Acquisition of non-controlling interest in U.S. Wind farms

On March 31, 2014, APCo acquired the remaining 40% interest in Wind Portfolio SponsorCo, LLC ("SponsorCo") not owned by APCo for approximately U.S. $115,000. SponsorCo indirectly holds the interests in Sandy Ridge, Senate and Minonk Wind acquired in 2012. As a result of the transaction, APCo now owns 100% of SponsorCo resulting in the elimination of the non-controlling interest in respect of the Class B partnership units of SponsorCo as follows:

Elimination of non-controlling interest in Class B partnership units	$	205,796
Non-controlling interest portion of currency translation adjustment recorded to AOCI		(21,029)
Non-controlling interest portion of unrealized gain on cash flow hedges recorded to AOCI		(2,543)
Decrease in deferred income tax asset		(32,551)
Additional paid-in capital		(22,413)
Cash	$	127,260

(b) Acquisition of New England Gas System

On December 20, 2013, Liberty Utilities acquired certain regulated natural gas distribution utility assets (the "New England Gas System") located in the State of Massachusetts. Total purchase price for the New England Gas System, net of the debt assumed, is approximately $67,010 (U.S. $62,745). The purchase price adjustment was finalized in Q2 2014 to reflect an increase of U.S. $3,108 million from the estimates available on acquisition in December 2013.

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

Working capital	$	7,846
Restricted cash		595
Property, plant and equipment		83,365
Regulatory assets		51,462
Other assets		1,221
Long-term debt		(25,349)
Regulatory liabilities		(9,874)
Pension and OPEB		(25,681)
Environmental obligation		(14,933)
Deferred income tax liability, net		(1,158)
Other liabilities		(484)
Total net assets acquired	$	67,010

The Company has not completed the fair value measurements of the assets acquired and liabilities assumed. Currently, the determination of the fair value has been based upon management's preliminary estimates of final closing adjustments, certain estimates and assumptions with respect to the fair values of the assets acquired and liabilities assumed. The Company will continue to review information and perform further analysis prior to finalizing the fair value of the consideration paid and the fair value of the assets acquired and liabilities assumed. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts above. The table above reflects the purchase price from the estimates available on acquisition in December 2013 up to and including any changes in estimates to the end of September 2014.

Property, plant and equipment are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of New England Gas System assets is 31 years.

3. Business acquisitions and development projects (continued)

(b) Acquisition of New England Gas System (continued)

All costs related to the acquisition have been expensed through the unaudited interim consolidated statements of operations.

New England Gas System contributed revenue of $8,214 and $72,542 and net earnings/(loss) of $(3,519) and $7,988 to the Company's consolidated financial results for three and nine months ended September 30, 2014.

(c) Acquisition of Shady Oaks Wind Facility

Effective January 1, 2013, APCo acquired the 109.5 megawatt ("MW") Shady Oaks wind powered generating facility ("Shady Oaks Wind Facility"). The purchase agreement provides for final purchase price adjustments based on working capital at the acquisition date, energy generated by the project and basis differences between the relevant node and hub prices which are expected to be finalized in the fourth quarter of 2014. Changes in measurement of the final purchase price adjustment subsequent to December 31, 2013, the end of the business combination measurement period, are recorded in current period operations. To that effect, a gain of U.S. $Nil and U.S. $1,133 was recognized in the three and nine months ended September 30, 2014, respectively.

(d) Development of Cornwall Solar Facility

On January 4, 2012, APCo acquired rights to develop a 10 MWac solar project located near Cornwall, Ontario. As at September 30, 2014, the Company has invested $40,235 in the development and construction of the solar energy project which is recorded as property, plant and equipment, as well as additional amounts related to development rights and other intangible assets, for a total investment of $46,245. The facility commenced commercial operations on March 27, 2014.

(e) Development of Bakersfield Solar Project

APCo acquired the development rights to a 20 MWac solar powered generating station located in Kern County, California.

On August 13, 2014, APCo entered into a definitive partnership agreement with a third party (the "Tax Investor"). It is anticipated that the total expected capital costs for the project of U.S. $58,500 will be funded approximately 62% by APCo and the balance by the Tax Investor. With its partnership interest, the Tax Investor will receive the majority of the tax attributes associated with the project. The Tax Equity investment as at September 30, 2014 is negligible.

Under certain conditions, the Tax Investor has the right to withdraw from the Bakersfield Solar Project and require APCo to redeem its interests for cash over a contractual payment period. As a result, the Company will account for this interest as temporary equity and will record this interest outside of permanent equity on the consolidated balance sheet as "redeemable non-controlling interest". The Company records temporary equity at issuance based on cash received less any transaction costs. As at September 30, 2014, transaction costs of $956 have been deferred and recorded as part of other assets. Once the Tax Investor has fully contributed its investment, deferred transaction costs will be recorded as a reduction to redeemable non-controlling interest.

At each consolidated balance sheet date, the Company will reevaluate the classification of its redeemable instruments, 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.

3. Business acquisitions and development projects (continued)

(e) Development of Bakersfield Solar Project (continued)

As at September 30, 2014, the Company has invested $32,000 in the development and construction of the solar energy project which is recorded as construction in progress, as well as additional amounts related to development rights and other intangible assets, for a total investment of $34,052. The commencement of operations is planned for early 2015.

(f) Agreement to acquire Park Water System

On September 19, 2014, Liberty Utilities 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 the latter half of 2015.

4. Accounts receivable

Accounts receivable as at September 30, 2014 includes unbilled revenue of $18,400 (December 31, 2013 - $45,274) from the Company's regulated utilities. Accounts receivable as at September 30, 2014 is presented net of allowance for doubtful accounts of $12,784 (December 31, 2013 - $8,461).

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 Topic 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, Liberty Utilities can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the unaudited interim financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period.

On January 22, 2014, Liberty Utilities' Granite State Electric System entered a settlement with the New Hampshire Public Utilities Commission Staff in connection with its rate application filed on March 29, 2013. The settlement provides for a rate increase of U.S. $10,875 consisting of U.S. $9,760 in base rates and an additional U.S. $1,115 for incremental capital expended after the test year. In addition, the settlement allows for a one time recovery of rate case expenses of U.S. $390. The settlement was approved on March 17, 2014 with the new permanent rates effective as of April 1, 2014 for effect with service rendered on and after July 1, 2013.

On April 18, 2014, Liberty Utilities' LPSCo Water System received a Final Order from the Arizona Corporation Commission approving a rate increase of U.S. $1,767 in connection with its rate application filed on February 28, 2013. The new rates became effective on May 1, 2014.

In January 2014, Liberty Utilities' Peach State Gas System and the Staff of the Georgia Public Service agreed to a settlement which will provide an annual revenue increase of U.S. $4,759 in connection with its annual GRAM filing on October 30, 2013. Commission approval was received in May 2014, with new rates effective as of June 1, 2014.

5. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

	September 30, 2014	December 31, 2013
Regulatory assets		
Environmental costs	$ 96,486	$ 85,029
Pension and post-employment benefits	64,053	64,997
Commodity costs adjustment	36,984	15,904
Storm costs	3,709	5,437
Debt premium	4,556	4,504
Rate case costs	3,455	3,119
Vegetation management	3,050	2,297
Rate adjustment mechanism	5,802	28
Asset retirement obligation	1,605	1,468
Tax related	3,873	2,995
Other	8,211	4,570
Total regulatory assets	$ 231,784	$ 190,348
Less current regulatory assets	(53,466)	(26,125)
Non-current regulatory assets	$ 178,318	$ 164,223
Regulatory liabilities		
Cost of removal	$ 74,770	$ 68,698
Rate-base offset	23,460	25,082
Commodity costs adjustment	10,290	17,394
Pension and post-employment benefits	1,061	6,770
Rate adjustment mechanism	456	1,681
Storm costs	714	—
Tax related	140	133
Other	5,687	3,531
Total regulatory liabilities	$ 116,578	$ 123,289
Less current regulatory liabilities	(16,649)	(21,632)
Non-current regulatory liabilities	$ 99,929	$ 101,657

6. Long-term investments and notes receivable

Long-term investments and notes receivable consist of the following:

	September 30, 2014	December 31, 2013
Long-term investments		
32.4% of Class B non-voting shares of Kirkland Lake Power Corp. (a)	$ 1,512	$ 4,851
25% of Class B non-voting shares of Cochrane Power Corporation (a)	—	3,772
50% interest in the Valley Power Partnership	1,542	1,718
Other	617	325
	$ 3,671	$ 10,666
Less: current portion	(132)	—
Total long-term investments	$ 3,539	$ 10,666
Notes receivable		
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%	800	1,928
Development loans (b)	6,357	—
Silverleaf resorts loan, interest at 15.48% maturing July 2020	2,263	2,149
Other	661	448
	28,234	22,678
Less: current portion	(648)	(598)
Total long-term notes receivable	$ 27,586	$ 22,080
Total non-current long-term investments and notes receivable	$ 31,125	$ 32,746

(a) Kirkland Lake Power Corp. and Cochrane Power Corporation

In September 2014, APCo was informed that future cash flows from its investments in Kirkland Lake Power Corp ("Kirkland") and Cochrane Power Corporation ("Cochrane") are likely to be significantly reduced in the future based on the current power purchase rates negotiations. As the loss in value of these investment is considered other than temporary, an allowance for impairment of $3,414 and $3,772 on Kirkland and Cochrane respectively was recorded in the unaudited interim consolidated statement of operations. The fair value of the investments was estimated using cash flow information provided by the investees.

(b) Odell Wind Project

On September 4, 2014, APCo announced an opportunity to acquire an interest in the Odell Wind Farm LLC (“Odell”), which owns a 200 MW construction-stage wind development project (“Odell Wind Project”) in the state of Minnesota. APCo is continuing its engineering, regulatory and financial analysis in respect of the Odell Wind Project to ensure that it meets all of APCo’s requirements for an approved development project. The total construction costs of the Odell Wind Project are estimated to be U.S. $322,766.

7. Long-term liabilities

Long-term liabilities consist of the following:

	September 30, 2014	December 31, 2013
APUC		
Revolving unsecured credit facility	$ —	$ —
APCo		
Revolving unsecured credit facility	53,838	124,570
Senior unsecured notes	484,535	284,757
Senior Debt - Shady Oaks Wind Facility	88,480	129,759
Senior Debt - Long Sault Hydro Facility	36,333	37,143
Senior Debt - Sanger Thermal Facility	21,504	20,421
Senior Debt - Chuteford Hydro Facility	3,129	3,417
Liberty Utilities		
Revolving unsecured credit facility	126,224	85,620
Senior unsecured notes - Liberty Utilities Co.	408,800	388,214
Senior unsecured notes - Calpeco Electric System	78,400	74,452
Senior unsecured notes - Liberty Water Co.	56,000	53,180
Senior unsecured notes - Granite State Electric System	16,800	15,954
First mortgage bonds - New England Gas System	26,404	25,244
IDA Bonds - LPSCo Water System	11,880	11,668
Loans - Bella Vista Water System	1,146	1,189
	$ 1,413,473	$ 1,255,588
Less: current portion	(8,822)	(8,339)
	$ 1,404,651	$ 1,247,249

APCo

On January 17, 2014, APCo issued $200,000 senior unsecured debentures bearing interest at 4.65% and with a maturity date of February 15, 2022. The debentures were sold at a price of $99.864 per $100.00 principal amount. Interest payments are payable on February 15 and August 15 each year, commencing on February 15, 2014. APCo incurred deferred financing costs of $1,568, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Concurrent with the offering, APCo entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars. APCo designated the entire notional amount of the cross currency fixed for fixed interest rate swap and related short-term USD payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in APCo'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 USD 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 other comprehensive income) related to the net investment.

On July 31, 2014, APCo increased the credit available under the senior unsecured credit facility to $350,000 from $200,000. The larger facility will be used to provide additional liquidity in support of APCo's development portfolio to be completed over the next three years. The maturity of the facility has been extended to July 31, 2018.

8. Pension and other post-employment benefits

The following tables list the components of net benefit costs for the pension plans and other post-employment benefits ("OPEB") recorded in the unaudited interim consolidated statements of operations. The employee benefit costs related to business acquired are recorded in the unaudited interim consolidated statements of operations from the date of acquisition.

	Pension benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Service cost	$ 1,286	$ 892	$ 3,878	$ 2,517
Interest cost	2,017	1,120	6,081	3,203
Expected return on plan assets	(2,447)	(1,062)	(7,375)	(3,022)
Amortization of net actuarial (gain)/loss	(83)	6	(252)	17
Amortization of net regulatory assets/liabilities	491	123	1,482	365
Net benefit cost	$ 1,264	$ 1,079	$ 3,814	$ 3,080

	OPEB			
	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Service cost	$ 520	$ 431	$ 1,568	$ 1,166
Interest cost	534	387	1,608	1,097
Expected return on plan assets	(156)	(152)	(469)	(448)
Amortization of net actuarial (gain)/loss	(156)	10	(469)	29
Amortization of net regulatory assets/liabilities	43	52	129	155
Net benefit cost	$ 785	$ 728	$ 2,367	$ 1,999

9. Shareholders' capital

(a) Common shares

Number of common shares:

	September 30, 2014
Common shares, beginning of period	206,348,985
Issuance of shares under the dividend reinvestment and employee share purchase plans	1,668,494
Shares issued pursuant to public offering (b)	19,389,000
Common shares, end of period	227,406,479

(b) Public offering of common shares

In September 2014, APUC issued 19,389,000 common shares at $8.90 per share pursuant to a public offering for proceeds of $172,562, before issuance costs of $7,281 or $5,352 net of taxes.

(c) Subscription receipts

Subsequent to quarter end, in October 2014, APUC issued 8,708,170 subscription receipts to Emera Inc. ("Emera") at a price of $8.90 per share. At any time after the closing of the Odell Acquisition (note 6(b)), Emera may elect to convert the Subscription Receipts for no additional consideration on a one-for-one basis into common shares. In the event that Emera has not elected to convert the subscription receipts by the second anniversary of the closing of the Odell Acquisition, they will automatically convert into Common Shares.

(d) Preferred shares

On March 5, 2014, APUC issued 4,000,000 Series D Preferred shares, at a price of $25 per share, for aggregate proceeds of $100,000 before issuance costs of $3,726 or $2,739 net of taxes.

The holders of the Series D Preferred shares are entitled to receive fixed cumulative preferential dividends at an annual rate of $1.25 per share, payable quarterly, as and when declared by the Board of Directors of APUC (the "Board"). The Series D Preferred shares yield 5.0% annually for the initial five-year period up to, but excluding March 31, 2019, with the first dividend payment occurring June 30, 2014. The dividend rate will reset on March 31, 2019, and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 3.28%. The Series D Preferred shares are redeemable at $25 per share at the option of the Company on March 31, 2019, and on March 31 of every fifth year thereafter. The holders of Series D Preferred shares have the right to convert their shares into Cumulative Floating Rate Preferred shares, Series E (the "Series E Preferred shares"), subject to certain conditions, on March 31, 2019, and on March 31 of every fifth year thereafter. The Series E Preferred shares carry the same features as the Series D Preferred shares, except that holders will be entitled to receive quarterly floating-rate cumulative dividends, as and when declared by the Board, at a rate equal to the then ninety-day Government of Canada treasury bill yield plus 3.28%. The holders of Series E Preferred shares will have the right to convert their shares back into Series D Preferred shares on March 31, 2019, and on March 31 of every fifth year thereafter. The Series D Preferred shares and the Series E Preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

(e) Share-based compensation

On May 13, 2014, the Board approved the grant of 969,999 options to executives of the Company. The options allow for the purchase of common shares at a price of $7.95, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2015, 2016 and 2017. Options may be exercised up to eight years following the date of grant.

During the nine months ended September 30, 2014, 27,301 Deferred Share Units ("DSU") were issued pursuant to the election of the Directors to defer a percentage of their 2014 Directors' fee in the form of DSUs.

9. Shareholders' capital (continued)

(e) Share-based compensation (continued)

During the second quarter, the Company settled 22,665 vested performance share units ("PSUs") for $162 in cash. 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.

During the third quarter, the Board approved the grant of 386,071 PSUs to executives and employees of the Company. A tranche of 164,813 PSUs vests on December 31, 2015 while the balance of 221,258 PSUs vests on December 31, 2016. The number of shares to be issued can range from 0% to 187% of the number of PSUs granted based on established performance criteria.

For the three and nine months ended September 30, 2014, APUC recorded $1,130 and $2,122 (2013 - $563 and $1,551) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the unaudited interim consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at September 30, 2014, total unrecognized compensation costs related to non-vested options and share unit awards were $2,665 and $2,592, respectively, and are expected to be recognized over a period of 1.81 and 1.81 years, respectively.

10. Accumulated other comprehensive loss

Accumulated other comprehensive loss is comprised 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 loss	Total
Balance, January 1, 2013	$(105,957)	$ 3,596	$ —	$ (2,506)	$(104,867)
Other comprehensive income before reclassifications	48,486	10,357	—	16,698	75,541
Amounts reclassified from accumulated other comprehensive income	—	(2,113)	—	29	(2,084)
Net current period other comprehensive income	48,486	8,244	—	16,727	73,457
Balance, December 31, 2013	$ (57,471)	$ 11,840	$ —	$ 14,221	$ (31,410)
Other comprehensive income/(loss) before reclassifications	41,412	(8,913)	519	—	33,018
Amounts reclassified from accumulated other comprehensive income/(loss)	—	8,283	(518)	(739)	7,026
Net current period other comprehensive income/(loss)	41,412	(630)	1	(739)	40,044
Acquisition of non-controlling interest in U.S. Wind farms (note 3(a))	21,029	2,543	—	—	23,572
Balance, September 30, 2014	$ 4,970	$ 13,753	$ 1	$ 13,482	$ 32,206

Amounts reclassified from accumulated other comprehensive loss for unrealized gain/(loss) on cash flow hedges affected revenue from non-regulated energy sale while those for pension and post-employment actuarial loss affected administrative expenses.

11. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board of the Company. For the three and nine months ended September 30, 2014, the Company declared dividends to shareholders on common shares totaling $22,286 and $57,503, respectively (2013 - $17,479 and $50,751) or $0.0980 (U.S. $0.0875) and $0.268, respectively per common share (2013 - $0.085 and $0.2475 per common share).

On August 14, 2014, the Board approved a common share dividend increase to U.S. $0.35, paid quarterly at a rate of U.S. $0.0875.

The Board declared a dividend on the Company's common shares of U.S. $0.0875 per share payable on October 15, 2014 to the shareholders of record on September 30, 2014.

For the three and nine months ended September 30, 2014, the Company declared and paid dividends to Preferred Share, Series A holders totaling $1,350 and $4,050, respectively (2013 - $1,350 and $4,050) or $0.28125 and $0.84375, respectively per Preferred Share, Series A (2013 - $0.28125 and $0.84375 per Series A Preferred share).

For the three and nine months ended September 30, 2014, the Company declared dividends to Preferred Share, Series D holders totaling $1,250 and $2,853, respectively (2013 - $nil) or $0.3125 and $0.7132 per Series D Preferred share (2013 - $nil per Series D Preferred share).

12. Divestitures

(a) EFW held for sale

During the second quarter of 2013, the Company initiated a strategic review of the Company's business plan and opportunities available for its Energy From Waste ("EFW Thermal Facility") and Brampton Cogeneration Inc. ("BCI Thermal Facility"). As a result of the review, the Company decided to sell the facilities. In 2013, the net assets of EFW and BCI were written down to their estimated fair value less cost of sale which resulted in a write down of the net assets of $56,851 before tax, or $42,538 net of tax of $14,313.

On February 7, 2014, the Company entered into an agreement to sell EFW and BCI Thermal Facilities and the transaction closed on April 4, 2014 for its estimated fair value and is subject to final post closing adjustments.

(b) Sale of U.S. Hydro facilities

On June 29, 2013, APCo sold 9 small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of the Company, for gross proceeds of U.S. $23,400 for a gain on sale of U.S. $960, net of tax recovery of U.S. $1,605.

On June 16, 2014, APCo sold its final small U.S. hydroelectric generating facility for U.S. $3,600.

12. Divestitures (continued)

(c) Results from discontinued operations

The assets of EFW and BCI Thermal Facilities and the small U.S. hydroelectric facilities are presented as assets held for sale on the unaudited interim consolidated balance sheets and the operating results from these facilities are disclosed as discontinued operations on the unaudited interim consolidated financial statements.

The summary of operating results and cash flows from discontinued operations for the three and nine months ended September 30 is as follows:

	Three months ended September 30,	
	2014	**2013**
Non-regulated energy sales	$ —	$ 1,601
Waste disposal fees	—	2,033
Other and interest income	—	38
Operating and administrative expenses	61	(4,504)
Foreign exchange	61	(26)
Interest expense	12	43
Loss on sale of assets	(462)	(140)
Write-down of other assets	(94)	—
Write-down of liabilities	105	—
Loss from discontinued operations, before income taxes	(317)	(955)
Income tax recovery	103	655
Loss from discontinued operations, net of income taxes	(214)	(300)
Add:		
Write-down of other assets	94	—
Write-down of liabilities	(105)	—
Income tax recovery	(103)	(655)
Cash used in discontinued operations	$ (328)	$ (955)

12. Divestitures (continued)

(c) Results from discontinued operations (continued)

	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Non-regulated energy sales	$ 2,174	$ 7,657
Waste disposal fees	2,233	5,983
Other and interest income	63	291
Operating and administrative expenses	(5,217)	(15,267)
Foreign exchange	65	41
Depreciation of property, plant and equipment	—	(2,483)
Interest expense	(19)	(44)
Gain/(loss) on sale of assets	(80)	1,015
Write-down of assets	(450)	(47,651)
Write-down of liabilities	105	—
Write-down of other assets	(94)	—
Deposit on sale	143	—
Loss from discontinued operations, before income taxes	(1,077)	(50,458)
Income tax recovery	431	15,118
Loss from discontinued operations, net of income taxes	(646)	(35,340)
Add:		
Depreciation of property, plant and equipment	—	2,483
Write off of accounts receivable	(143)	—
Write-down of assets	450	47,651
Write-down of liabilities	(105)	—
Write-down of other assets	94	—
Contingent liability	—	(613)
Income tax recovery	(431)	(15,118)
Cash used in discontinued operations	$ (781)	$ (937)

Assets held for sale were as follows:

	September 30, 2014	December 31, 2013
Property, plant and equipment	$ —	$ 21,193
Accounts receivable and prepaid expenses	1,792	2,734
Total assets held for sale, current	$ 1,792	$ 23,927

Liabilities held for sale were as follows:

	September 30, 2014	December 31, 2013
Accounts payable and accrued liabilities	$ 1,300	$ 1,471

13. Related party transactions

A member of the Board of Directors of APUC is an executive at Emera. For the three and nine months ended September 30, 2014, the Energy Services Business sold electricity to Maine Public Service Company (“MPS”), a subsidiary of Emera, amounting to U.S. $1,506 and U.S. $4,518, respectively (2013 - U.S. $1,466 and U.S, $4,628). For the three and nine months ended September 30, 2014, Liberty Utilities purchased natural gas amounting to U.S. $149 and U.S. $4,891 (2013 - U.S. $38 and U.S. $750) 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.

Ian Robertson and Chris Jarratt ("Senior Executives"), Chief Executive Officer and Vice-Chair of APUC respectively, partially own an entity from which APUC leases its head office facilities. Base lease costs for the three and nine months ended September 30, 2014 were $78 and $236, respectively (2013 - $84 and $252). Subsequent to quarter end, APUC completed moving all head office employees into a new premises and has entered into a lease termination agreement with respect to the former head office facilities leased from an entity partially owned by Senior Executives. The lease termination agreement is for nominal consideration and is subject to the completion of a sale of the property to a third party pursuant to an agreement of purchase and sale which is expected to close before the end of 2014. Subsequent to the sale, there will be no further related party matter in relation to an office lease.

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 earnings/(loss) attributable to non-controlling interests consist of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Net earnings/(loss) attributable to Class B partnership units of SponsorCo	$ —	$ (921)	$ 3,483	$ 6,186
Net loss attributable to Class A partnership units	(2,350)	(1,033)	(18,325)	(13,597)
Other	333	—	990	39
Total net loss attributable to non-controlling interests	$ (2,017)	$ (1,954)	$ (13,852)	$ (7,372)

On March 31, 2014, APCo acquired the remaining Class B partnership units of SponsorCo from the non-controlling interest holder. As a result of the transaction, APCo now owns 100% of SponsorCo (note 3(a)).

15. Income taxes

For the nine months ended September 30, 2014, the Company’s overall effective tax rate was different than the statutory rate of 26.50% (2013 - 26.50%) due primarily to recognition of deferred credits, higher tax rates in U.S. subsidiaries, non-controlling interest partner’s tax expenses, inter-corporate dividends, and non deductible expenses.

Included in deferred income tax expense for the three and nine months ended September 30, 2014 is $281 and $2,401, respectively (2013 - $1,570 and $5,080) related to the recognition of deferred credits from the utilization of deferred income tax assets.

16. Basic and diluted net earnings per share

Basic and diluted net earnings/(loss) per share have been calculated on the basis of net earnings/(loss) attributable to the common shareholders of the Company and the weighted average number of common shares outstanding during the period. Diluted net earnings/(loss) per share is computed using the weighted average number of common shares and, if dilutive, potential common shares outstanding during the period. Potential common shares consist of the incremental common shares issuable upon the exercise of stock options, PSUs, DSUs and shareholders' rights. The dilutive effect of outstanding stock options, PSUs, DSUs and shareholders' rights is reflected in diluted net earnings/(loss) per share by application of the treasury stock method.

The reconciliation of the net earnings/(loss) and the weighted average shares used in the computation of basic and diluted net earnings/(loss) per share are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2014	**2013**	**2014**	**2013**
Net earnings/(loss) attributable to shareholders of APUC	$ (6,310)	$ 6,023	$ 44,140	$ 7,142
Series A Preferred shares dividend (note 11)	1,350	1,350	4,050	4,050
Series D Preferred shares dividend (note 11)	1,250	—	2,853	—
Net earnings/(loss) attributable to common shareholders of APUC	$ (8,910)	$ 4,673	$ 37,237	$ 3,092
Discontinued operations	(214)	(300)	(646)	(35,340)
Net earnings attributable to common shareholders of APUC from continuing operations - Basic and Diluted	$ (8,696)	$ 4,973	$ 37,883	$ 38,432
Weighted average number of shares				
Basic	210,791,056	205,527,475	208,322,421	203,721,023
Dilutive effect of share-based awards	—	896,957	1,374,256	1,040,399
Diluted	210,791,056	206,424,432	209,696,677	204,761,422

For the three and nine months ended September 30, 2014, the shares potentially issuable as a result of 5,537,127 and 1,786,401 stock options, respectively (2013 – 2,080,029 and 885,423) are excluded from this calculation as they are anti-dilutive.

17. Segmented information

APUC has two business units: APCo which owns or has interests in renewable energy facilities and thermal energy facilities and Liberty Utilities which owns and operates utilities in the United States of America providing water, wastewater and local electric and natural gas distribution services.

Within APCo there are two operating segments: Renewable Energy and Thermal Energy. The Renewable Energy division operates the Company's hydro-electric, solar energy, and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities.

Within Liberty Utilities there are the following operating segments: Liberty Utilities (West), Liberty Utilities (Central) and Liberty Utilities (East). Liberty Utilities (West) is comprised of Calpeco Electric System and the water distribution and wastewater utilities located in Arizona. Liberty Utilities (Central) is comprised of the Midwest Gas System and the water distribution and wastewater utilities located in Arkansas, Texas, Missouri and Illinois. Liberty Utilities (East) is comprised of the New Hampshire Electric and Gas Systems, Peach State Gas System and New England Gas System. Acquisition costs are not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment.

The development activities of APCo are reported under Renewable Energy or Thermal Energy as appropriate. 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 derivatives instruments not designated in a hedging relationship and acquisition costs are 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 as follows:

17. Segmented information (continued)

Operational segments (continued)

	Three months ended September 30, 2014								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ —	$ —	$ —	$ —	$ 19,505	$ 29,363	$ 48,868	$ —	$ 48,868
Regulated gas sales and distribution	—	—	—	8,085	—	34,159	42,244	—	42,244
Regulated water reclamation and distribution	—	—	—	5,457	11,736	—	17,193	—	17,193
Non-regulated energy sales	29,932	10,421	40,353	—	—	—	—	—	40,353
Other revenue	1,527	921	2,448	—	2	755	757	—	3,205
Total revenue	31,459	11,342	42,801	13,542	31,243	64,277	109,062	—	151,863
Operating expenses	12,088	2,232	14,320	8,410	8,988	26,369	43,767	15	58,102
Regulated electricity purchased	—	—	—	—	9,555	17,888	27,443	—	27,443
Regulated gas purchased	—	—	—	2,239	—	11,522	13,761	—	13,761
Non-regulated energy purchased	2,757	3,976	6,733	—	—	—	—	—	6,733
	16,614	5,134	21,748	2,893	12,700	8,498	24,091	(15)	45,824
Administrative expenses	(3,301)	(87)	(3,388)	(819)	(1,229)	(2,206)	(4,254)	(550)	(8,192)
Depreciation of property, plant and equipment	(11,950)	(1,543)	(13,493)	(3,358)	(3,752)	(6,467)	(13,577)	(541)	(27,611)
Amortization of intangible and other assets	(940)	(219)	(1,159)	510	(381)	(1,894)	(1,765)	—	(2,924)
Foreign exchange loss	—	—	—	—	—	—	—	491	491
Interest expense	(8,420)	(441)	(8,861)	(1,421)	(2,056)	(3,186)	(6,663)	(404)	(15,928)
Interest, dividend and other income	523	(210)	313	28	388	260	676	694	1,683
Write down on long-lived assets	—	—	—	—	6	—	6	(7,186)	(7,180)
Acquisition-related costs	—	—	—	—	—	—	—	(448)	(448)
Gain on derivative financial instruments	716	—	716	—	—	—	—	919	1,635
Earnings/(loss) from continuing operations before income taxes	(6,758)	2,634	(4,124)	(2,167)	5,676	(4,995)	(1,486)	(7,040)	(12,650)
Earnings/(loss) from discontinued operations before income taxes	(488)	171	(317)	—	—	—	—	—	(317)
Earnings/(loss) before income taxes	$ (7,246)	$ 2,805	$ (4,441)	$ (2,167)	$ 5,676	$ (4,995)	$ (1,486)	$ (7,040)	$ (12,967)
Capital expenditures	$ 61,461	$ 514	$ 61,975	$ 7,921	$ 8,658	$ 28,411	$ 44,990	$ 4,324	$ 111,289

17. Segmented information (continued)

Operational segments (continued)

	Nine months ended September 30, 2014								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ —	$ —	$ —	$ —	$ 59,954	$ 92,310	$ 152,264	$ —	$ 152,264
Regulated gas sales and distribution	—	—	—	66,546	—	254,824	321,370	—	321,370
Regulated water reclamation and distribution	—	—	—	15,761	32,454	—	48,215	—	48,215
Non-regulated energy sales	114,919	33,844	148,763	—	—	—	—	—	148,763
Other revenue	8,945	2,480	11,425	—	7	2,201	2,208	—	13,633
Total revenue	123,864	36,324	160,188	82,307	92,415	349,335	524,057	—	684,245
Operating expenses	35,097	7,410	42,507	24,545	27,343	82,359	134,247	45	176,799
Regulated electricity purchased	—	—	—	—	29,738	56,610	86,348	—	86,348
Regulated gas purchased	—	—	—	39,727	—	146,510	186,237	—	186,237
Non-regulated energy purchased	15,146	17,651	32,797	—	—	—	—	—	32,797
	73,621	11,263	84,884	18,035	35,334	63,856	117,225	(45)	202,064
Administrative expenses	(9,718)	(256)	(9,974)	(2,495)	(4,066)	(7,134)	(13,695)	(496)	(24,165)
Depreciation of property, plant and equipment	(35,954)	(4,453)	(40,407)	(9,294)	(10,640)	(17,438)	(37,372)	(1,546)	(79,325)
Amortization of intangible and other assets	(2,279)	(662)	(2,941)	1,278	(1,177)	(2,899)	(2,798)	—	(5,739)
Foreign exchange gain	—	—	—	—	—	—	—	1,422	1,422
Interest expense	(25,106)	(1,419)	(26,525)	(4,248)	(6,311)	(9,954)	(20,513)	(1,244)	(48,282)
Interest, dividend and other income	1,301	(231)	1,070	178	1,237	1,052	2,467	2,700	6,237
Gain on asset disposal	—	326	326	—	—	—	—	—	326
Write down on long-lived assets	—	(698)	(698)	—	(287)	—	(287)	(7,186)	(8,171)
Acquisition-related costs	—	—	—	—	—	—	—	(945)	(945)
Gain/(loss) on derivative financial instruments	857	—	857	—	—	—	—	(202)	655
Earnings/(loss) from continuing operations before income taxes	2,722	3,870	6,592	3,454	14,090	27,483	45,027	(7,542)	44,077
Earnings/(loss) from discontinued operations before income taxes	(1,204)	127	(1,077)	—	—	—	—	—	(1,077)
Earnings/(loss) before income taxes	$ 1,518	$ 3,997	$ 5,515	$ 3,454	$ 14,090	$ 27,483	$ 45,027	$ (7,542)	$ 43,000
Capital expenditures	$ 137,444	$ 3,516	$ 140,960	$ 21,356	$ 18,321	$ 59,821	$ 99,498	$ 50,207	$ 290,665
Acquisition of operating entities	—	—	—	4,878	—	3,967	8,845	—	8,845

17. Segmented information (continued)

Operational segments (continued)

	Three months ended September 30, 2013								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ —	$ —	$ —	$ —	$ 18,540	$ 24,396	$ 42,936	$ —	$ 42,936
Regulated gas sales and distribution	—	—	—	8,951	—	19,984	28,935	—	28,935
Regulated water reclamation and distribution	—	—	—	5,209	10,643	—	15,852	—	15,852
Non-regulated energy sales	28,639	9,246	37,885	—	—	—	—	—	37,885
Other revenue	1,764	544	2,308	—	2	—	2	—	2,310
Total revenue	30,403	9,790	40,193	14,160	29,185	44,380	87,725	—	127,918
Operating expenses	10,498	1,182	11,680	7,474	9,184	18,363	35,021	—	46,701
Regulated electricity purchased	—	—	—	—	8,941	14,956	23,897	—	23,897
Regulated gas purchased	—	—	—	2,984	—	4,837	7,821	—	7,821
Non-regulated energy purchased	1,570	3,505	5,075	—	—	—	—	—	5,075
	18,335	5,103	23,438	3,702	11,060	6,224	20,986	—	44,424
Administrative expenses	(3,818)	112	(3,706)	(568)	1,111	(765)	(222)	(2,234)	(6,162)
Depreciation of property, plant and equipment	(12,484)	30	(12,454)	(2,027)	(3,521)	(4,545)	(10,093)	—	(22,547)
Amortization of intangible and other assets	(663)	(216)	(879)	355	(482)	(106)	(233)	—	(1,112)
Foreign exchange gain	—	—	—	—	—	—	—	(881)	(881)
Interest expense	(6,586)	(364)	(6,950)	(630)	(3,751)	(2,169)	(6,550)	(407)	(13,907)
Interest, dividend and other income	436	305	741	127	276	(252)	151	453	1,345
Gain on asset disposal	(118)	—	(118)	—	—	—	—	—	(118)
Write down on long-lived assets	(16)	—	(16)	—	—	—	—	—	(16)
Acquisition-related costs	—	—	—	—	—	—	—	(486)	(486)
Gain/(loss) on derivative financial instruments	(808)	—	(808)	—	—	—	—	1,394	586
Earnings/(loss) from continuing operations before income taxes	(5,722)	4,970	(752)	959	4,693	(1,613)	4,039	(2,161)	1,126
Loss from discontinued operations before income taxes	(489)	(466)	(955)	—	—	—	—	—	(955)
Earnings/(loss) before income taxes	$ (6,211)	$ 4,504	$ (1,707)	$ 959	$ 4,693	$ (1,613)	$ 4,039	$ (2,161)	$ 171
Capital expenditures	$ 17,106	$ —	$ 17,106	$ 6,744	$ 6,706	$ 9,319	$ 22,769	$ —	$ 39,875

17. Segmented information (continued)

Operational segments (continued)

	Nine months ended September 30, 2013								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ —	$ —	$ —	$ —	$ 57,119	$ 65,025	$ 122,144	$ —	$ 122,144
Regulated gas sales and distribution	—	—	—	54,153	—	113,453	167,606	—	167,606
Regulated water reclamation and distribution	—	—	—	13,513	29,213	—	42,726	—	42,726
Non-regulated energy sales	105,349	26,010	131,359	—	—	—	—	—	131,359
Other revenue	4,467	1,668	6,135	—	19	—	19	—	6,154
Total revenue	109,816	27,678	137,494	67,666	86,351	178,478	332,495	—	469,989
Operating expenses	29,041	6,431	35,472	20,916	27,066	47,907	95,889	—	131,361
Regulated electricity purchased	—	—	—	—	28,750	42,108	70,858	—	70,858
Regulated gas purchased	—	—	—	30,849	—	60,912	91,761	—	91,761
Non-regulated energy purchased	4,897	12,527	17,424	—	—	—	—	—	17,424
	75,878	8,720	84,598	15,901	30,535	27,551	73,987	—	158,585
Administrative expenses	(9,783)	(279)	(10,062)	(1,116)	(1,885)	(2,085)	(5,086)	(3,219)	(18,367)
Depreciation of property, plant and equipment	(32,930)	(4,051)	(36,981)	(6,065)	(9,806)	(13,163)	(29,034)	—	(66,015)
Amortization of intangible and other assets	(1,989)	(638)	(2,627)	1,021	(1,236)	(286)	(501)	—	(3,128)
Foreign exchange gain	—	—	—	—	—	—	—	437	437
Interest expense	(19,678)	(1,124)	(20,802)	(1,568)	(10,732)	(4,818)	(17,118)	(1,075)	(38,995)
Interest, dividend and other income	1,373	67	1,440	295	1,150	1,093	2,538	1,752	5,730
Gain on sale of asset	(118)	—	(118)	—	—	—	—	—	(118)
Write down on long-lived assets	(16)	—	(16)	—	—	—	—	—	(16)
Acquisition-related costs	—	—	—	—	—	—	—	(1,500)	(1,500)
Gain/(loss) on derivative financial instruments	(113)	—	(113)	—	—	—	—	2,603	2,490
Earnings/(loss) from continuing operations before income taxes	12,624	2,695	15,319	8,468	8,026	8,292	24,786	(1,002)	39,103
Earnings/(loss) from discontinued operations before income taxes	1,625	(52,083)	(50,458)	—	—	—	—	—	(50,458)
Earnings/(loss) before income taxes	$ 14,249	$ (49,388)	$ (35,139)	$ 8,468	$ 8,026	$ 8,292	$ 24,786	$ (1,002)	$ (11,355)
Capital expenditures	$ 29,063	$ 278	$ 29,341	$ 20,254	$ 10,374	$ 34,984	$ 65,612	$ 707	$ 95,660
Acquisition of operating entities	(1,698)	—	(1,698)	27,545	—	146,342	173,887	—	172,189

17. Segmented information (continued)

Operational segments (continued)

	September 30, 2014								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Property, plant and equipment	$1,518,796	$ 83,080	$1,601,876	$ 246,999	$ 413,528	$ 749,989	$1,410,516	$ 56,401	$3,068,793
Intangible assets	26,421	5,323	31,744	2,783	19,694	—	22,477	—	54,221
Total Assets held for sale	—	1,792	1,792	—	—	—	—	—	1,792
Total assets	1,648,872	102,886	1,751,758	316,105	489,092	1,087,274	1,892,471	164,260	3,808,489

	December 31, 2013								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Property, plant and equipment	$1,364,843	$ 79,828	$1,444,671	$ 215,090	$ 387,715	$ 661,228	$1,264,033	$ —	$2,708,704
Intangible assets	26,802	5,698	32,500	2,709	19,207	—	21,916	—	54,416
Total Assets held for sale	3,860	20,067	23,927	—	—	—	—	—	23,927
Total assets	1,492,144	116,922	1,609,066	285,555	461,025	927,051	1,673,631	193,784	3,476,481

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 Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5,400 (including interest) to the government of Québec 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 $6,300. In 2012, the Company paid an amount of $1,884 to the government of Québec in relation to the early years covered by the claim in order to mitigate the impact of accruing interest on any amount ultimately determined to be payable or recoverable.

ii) The normal ongoing operations and historic activities of the Company are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the various federal and state or provincial environmental protection agencies in Canada and the United States.

Like many other industrial companies, natural gas and electric distribution utilities can generate some hazardous waste. Under federal and state laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of regulated utilities these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

Prior to their acquisition by Liberty Utilities, EnergyNorth Gas, Granite State Electric and New England Gas Systems were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Company is currently investigating and remediating, as necessary, those MGP and related sites in accordance with plans submitted to the agency with authority for each of the respective sites. The Company believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position.

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $72,147 which at discount rates ranging from 2.31% to 3.33% represents the recorded accrual of $71,100 as at September 30, 2014 (December 31, 2013 - $69,555).

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and, accordingly, as at September 30, 2014, the Company has reflected a regulatory asset of $96,486 (December 31, 2013 - $85,029) for the MGP and related sites (note 5).

(b) Commitments

As a result of the dam safety legislation passed in Quebec (Bill C93), 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 $7,300 over a period of five years related to compliance with the legislation. As a result of ice damage to one dam during the spring thaw, a reassessment of the remedial measures needing to be taken at that facility are under review.

18. Commitments and contingencies (continued)

(b) Commitments (continued)

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	$116,425	$13,326	$ —	$ —	$ —	$ —	$ 129,751
Gas delivery, service and supply agreements	52,258	36,818	24,648	22,365	21,997	70,175	228,261
Service agreements	24,364	29,785	30,644	29,489	29,078	469,638	612,998
Capital projects	32,533	—	—	—	—	—	32,533
Operating leases	5,486	4,705	4,163	3,863	3,658	86,283	108,158
Total	$231,066	$84,634	$59,455	$55,717	$54,733	$626,096	$1,111,701

19. Non-cash operating items

The changes in non-cash operating items from discontinued operations is comprised of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Accounts receivable	$ (137)	$ 315	$ 780	$ (118)
Prepaid expenses	79	70	36	(50)
Accrued liabilities	319	77	(46)	149
	$ 261	$ 462	$ 770	$ (19)

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Accounts receivable	$ 14,553	$ 13,373	$ 36,734	$ 8,259
Related party balances	—	(8)	—	22
Natural gas in storage	(15,179)	(9,524)	(9,294)	(9,973)
Supplies and consumables inventory	(979)	(130)	(1,689)	(2,419)
Income tax receivable	(19)	12	(20)	(20)
Prepaid expenses	4,878	(1,470)	2,758	(3,212)
Accounts payable	(4,526)	(12,303)	17,185	(22,640)
Accrued liabilities	(4,547)	8,165	(35,099)	(8,906)
Current income tax liability	1,503	1,067	1,143	1,638
Net regulatory assets and liabilities	(17,039)	(5,736)	(46,113)	3,034
	$(21,355)	$ (6,554)	$(34,395)	$(34,217)

20. Financial instruments

(a) Fair value of financial instruments

September 30, 2014	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 28,234	$ 30,808	$ —	$ —	$ 30,808
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	20,297	20,297	—	—	20,297
Energy contracts not designated as a cashflow hedge	2,330	2,330	—	—	2,330
Commodity contracts for regulated operations	56	56	—	56	—
Total derivative financial instruments	22,683	22,683	—	56	22,627
Total financial assets	$ 50,917	$ 53,491	$ —	$ 56	$ 53,435
Long-term liabilities	$ 1,413,473	$ 1,492,727	$506,469	$ 986,258	$ —
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	171	171	—	—	171
Cross-currency swaps designated as a foreign exchange hedge	20,154	20,154	—	20,154	—
Interest rate swaps not designated as a hedge	1,867	1,867	—	1,867	—
Commodity contracts for regulated operations	1,168	1,168	—	1,168	—
Total derivative financial instruments	23,360	23,360	—	23,189	171
Total financial liabilities	$ 1,436,833	$ 1,516,087	$506,469	$1,009,447	$ 171

20. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

December 31, 2013	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 22,678	$ 26,321	$ —	$ —	$ 26,321
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	31,971	31,971	—	—	31,971
Energy contracts not designated as a cashflow hedge	3,737	3,737	—	—	3,737
Cross-currency swap designated as a foreign exchange hedge	109	109	—	109	—
Commodity contracts for regulated operations	482	482	—	482	—
Total derivative financial instruments	36,299	36,299	—	591	35,708
Total financial assets	$ 58,977	$ 62,620	$ —	$ 591	$ 62,029
Long-term liabilities	$ 1,255,588	$ 1,261,340	$ 296,986	$ 964,354	$ —
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	4,781	4,781	—	—	4,781
Cross-currency swap designated as a foreign exchange hedge	7,947	7,947	—	7,947	—
Interest rate swaps not designated as a hedge	3,180	3,180	—	3,180	—
Commodity contracts for regulated operations	313	313	—	313	—
Total derivative financial instruments	16,221	16,221	—	11,440	4,781
Total financial liabilities	$ 1,271,809	$ 1,277,561	$ 296,986	$ 975,794	$ 4,781

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 (a level 2 measurement) as at September 30, 2014 and December 31, 2013 due to the short-term maturity of these instruments.

Notes receivable fair values 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.

APUC has long-term liabilities at fixed interest rates and variable rates. The estimated fair value is determined using a discounted cash flow method, using estimated 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 Red Lily conversion option is measured at fair value on a recurring basis using unobservable inputs (Level 3). The fair value is based on an income approach using an option pricing model that includes various inputs such as energy yield function from wind, estimated cash flows and a discount rate of 8.5%. The Company used a discount rate believed to be most relevant given the business strategy. There was no change in fair value of $nil during the nine months ended September 30, 2014 or 2013.

The Company's Level 3 fair value derivative instruments consist of energy contracts for energy sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from U.S. $17.40 to U.S. $188.46 as of September 30, 2014 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 Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the three or nine months ended September 30, 2014 or 2013.

20. Financial instruments (continued)

(b) Derivative instruments

Derivative instruments are recognized on the unaudited interim 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 accounting for these derivative instruments is subject to current 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 accompanying unaudited interim consolidated balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 5).

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

	2014
Financial contracts: Gas swaps	3,231,494
Gas options	1,489,434
	4,720,928

(ii) Cash flow hedges

APCo reduces the price risk on the expected future sale of power generation at the 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
Energy delivered less existing swap	December 2014	U.S. $	32.64	PJM Western HUB
Energy delivered less existing swap	December 2014	U.S. $	25.64	NI HUB
Energy delivered less existing swap	December 2014	U.S. $	27.39	ERCOT North HUB
109,135	December 2016	$	67.73	AESO
947,440	December 2022	U.S. $	42.81	PJM Western HUB
4,053,039	December 2022	U.S. $	30.25	NI HUB
4,429,717	December 2027	U.S. $	36.46	ERCOT North HUB

As at September 30, 2014, an amount receivable under the derivatives for the Sandy Ridge, Senate and Minonk Wind Facilities of $13,891 (December 31, 2013 - $7,344) was held as collateral by the counterparty.

20. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The following table summarizes changes in other comprehensive income/(loss) attributable to derivative financial instruments designated as a hedge, net of tax:

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Effective portion of cash flow hedge, gain	$ 12,483	$ 1,355	$ (6,588)	$ 10,463
Loss realized on cash flow hedge	(9)	—	(24)	(14)
	$ 12,474	$ 1,355	$ (6,612)	$ 10,449
Less non-controlling interest	—	—	5,982	(4,939)
Change in fair value of cash flow hedge in other comprehensive income/(loss) attributable to shareholders of Algonquin Power & Utilities Corp.	$ 12,474	$ 1,355	$ (630)	$ 5,510

The Company expects $3,538 of unrealized gains currently in accumulated other comprehensive loss to be reclassified into net earnings/(loss) within the next twelve months, as the underlying hedged transactions settle.

The ineffective portion of derivative financial instruments designated as a hedge is recorded as part of loss/(gain) on derivative financial instruments on the unaudited interim consolidated statements of operations (note 20(b)(iv)).

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

The Company periodically uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. 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.

Concurrent with its $150,000 and $200,000 debentures offering in December 2012 and January 2014, respectively, APCo entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. APCo designated the entire notional amount of the cross currency fixed for fixed interest rate swaps and related short-term USD payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The gain or loss related to the fair value changes of the swaps and the related foreign currency gains and losses on the USD 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 other comprehensive income/(loss)) related to the net investment. A foreign currency loss of $15,758 and $12,233, respectively (2013 - foreign currency gain of $2,558 and loss of $2,034) was recorded in other comprehensive income/(loss) during the three and nine months ended September 30, 2014.

(iv) Other derivatives

APCo 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 net earnings/(loss) as they occur.

20. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)		Pay floating price
28,910	March 2015	U.S. $	52.99	NBSO - Salisbury

For derivatives that are not designated as cash flow hedges, and for the ineffective portion of gains and losses on derivatives that are accounted as hedges, the changes in the fair value are immediately recognized in net earnings/(loss).

The effects on the unaudited interim consolidated statements of operations of derivative financial instruments consist of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Change in unrealized (gain)/loss on derivative financial instruments:				
Interest rate swaps	$ (471)	$ (241)	$(1,313)	$ (1,284)
Energy derivative contracts	(374)	(1,153)	1,508	(1,319)
Total change in unrealized loss/(gain) on derivative financial instruments	$ (845)	$ (1,394)	$ 195	$ (2,603)
Realized loss/(gain) on derivative financial instruments:				
Interest rate swaps	492	521	1,474	1,519
Energy derivative contracts	178	507	(3,788)	(194)
Total realized loss/(gain) on derivative financial instruments	$ 670	$ 1,028	$(2,314)	$ 1,325
Gain on derivative financial instruments	$ (175)	$ (366)	$(2,119)	$ (1,278)
Ineffective portion of derivatives financial instruments accounted for as designated hedges	(1,460)	(220)	1,464	(1,212)
Gain on derivative financial instruments	$ (1,635)	$ (586)	$ (655)	$ (2,490)

20. Financial instruments (continued)

(c) Risk management

Foreign currency risk

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.

APCo designates the amounts drawn on its bank credit facility denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The foreign currency transaction gain or loss on the outstanding U.S. dollar denominated balance of APCo's facility that is designated a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in other comprehensive income/(loss)) related to the net investment, to the extent it is effective as a hedge. During the three and nine months ended September 30, 2014, a foreign currency loss of $1,148 and $2,162 (2013 - foreign currency gain of $1,317 and foreign currency loss of $492) was recorded in other comprehensive income (loss).

Interest rate risk

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 facility, its interest rate swaps as well as interest earned on its cash on hand. The Company does not currently hedge that risk.

APCo is party to an interest rate swap whereby, the Company pays a fixed interest rate of 4.47% on a notional amount of $61,072 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. As at September 30, 2014, the estimated fair value of the interest rate swap was a liability of $1,867 (December 31, 2013 – liability of $3,180). This interest rate swap is not being accounted for as a hedge and, consequently, changes in fair value are recorded in net earnings/(loss) as they occur.

21. Comparative figures

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

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