2013 SECOND QUARTER REPORT

Algonquin Power & Utilities Corp.

Interim Management's Discussion and Analysis

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

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and six months ended June 30, 2013. The interim Management's Discussion and Analysis ("MD&A") should be read in conjunction with APUC's interim unaudited consolidated financial statements for the three and six months ended June 30, 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.

Caution concerning forward-looking statements and non-GAAP Measures

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.

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA"), "adjusted funds from operations", "per share cash provided by adjusted funds from operations" and "per share cash provided by operating activities" are used throughout this MD&A. The terms "adjusted net earnings", "per share cash provided by operating activities", "adjusted funds from operations", "per share cash provided by adjusted funds from operations" and Adjusted EBITDA are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations" and "per share cash provided by operating activities" consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations" and "per share cash provided by operating activities" 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.

Overview and Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution and transmission utility assets which deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through a quarterly dividend augmented by share price appreciation arising from dividend growth supported by increasing per share cash flows and earnings. APUC targets to deliver annualized per share earnings and cash flow growth of more than 5%.

APUC's current quarterly dividend to shareholders is $0.085 per share or $0.34 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities and mitigate the impact of fluctuations in foreign exchange rates. Further increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board") with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC conducts its business primarily through two autonomous subsidiaries: Algonquin Power Co. ("APCo") which owns and operates a diversified portfolio of non-regulated renewable and clean energy electric generation utility assets; and Liberty Utilities Co. ("Liberty Utilities"), a diversified rate regulated utility which owns and operates a portfolio of North American electric, natural gas and water distribution utility systems.

Algonquin Power Co.

APCo generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable and clean energy power generation facilities located across North America. APCo delivers 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. APCo also owns or has interests in wind powered generating stations with a combined generating capacity of 650 MW. Approximately 84% of the electrical output from the hydroelectric and wind generating facilities is sold pursuant to long term, stipulated price contractual arrangements which have a weighted average remaining contract life of 15 years.

APCo owns or has interests in thermal energy facilities with approximately 335 MW of installed generating capacity. Approximately 95% 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 7 years.

Liberty Utilities Co.

Liberty Utilities is a diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services. 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 encouraging and supporting organic growth within its service territories, Liberty Utilities delivers continued growth in earnings through accretive acquisitions of additional utility systems.

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 systems serve approximately 47,000 active electric connections in the State of California. Liberty Utilities (West) region's regulated water and wastewater utility systems serve approximately 68,000 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 81,000 active natural gas connections located in the States of Missouri, Illinois, and Iowa and the regulated water distribution and wastewater collection utilities serve approximately 29,000 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

State of Georgia. In New Hampshire, Liberty Utilities provides regulated local electrical utility services to approximately 44,000 active electric connections; and regulated local gas distribution utility services to approximately 84,000 active natural gas connections. In Georgia, Liberty Utilities provides regulated local gas distribution utility services to approximately 58,000 active natural gas connections. Upon completion of the acquisition of a natural gas utility system located in Massachusetts, over 50,000 active natural gas connections will be added to the Liberty Utilities (East) region.

Major Highlights

Corporate Highlights

Strong second quarter results

APUC has completed several acquisitions and has announced a number of other initiatives that have raised the growth profile for APUC's earnings and cash flows. The growth arose from the acquisition of several regulated utilities in the U.S. serving over 290,000 customers together with the acquisition of 509.5 MW of wind farms also in the U.S. The increased earnings and cash flows from these acquisitions continued through the second quarter. Adjusted EBITDA totaled $56.5 million in the second quarter and $118.9 million year to date compared to $22.2 million and $43.4 million respectively.

Dividend Increased to $0.34 Per Common Share Annually

The increased earnings and cash flows in APUC's second quarter results have supported an increase in the dividend to shareholders. As a result, on May 9, 2013, the Board approved a dividend increase of $0.03 annually bringing the total annual dividend to $0.34, paid quarterly at the rate of $0.085 per common share.

Management believes that the increase in dividend 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.

Liberty Utilities Highlights

Agreement to Acquire New England Gas System

On February 11, 2013, Liberty Utilities entered into an agreement with The Laclede Group, Inc. ("Laclede") to assume Laclede's rights to purchase the assets of New England Gas Company (the "New England Gas System") from an affiliate of Southern Union Company. New England Gas System is a natural gas distribution utility serving over 50,000 active connections in Massachusetts. The acquisition is subject to certain approvals and conditions, including state and federal regulatory approval, and is expected to close in the fourth quarter of 2013. The results of the New England Gas System will be reported in the Liberty Utilities (East) region upon completion of the transaction.

Total consideration for the utility asset purchase is approximately U.S. $74 million, subject to working capital and closing adjustments. The acquisition will be funded using a targeted 52% equity, 48% debt capital structure and will include the assumption of $19.5 million of existing debt.

Acquisition of Georgia Gas System

On April 1, 2013 Liberty Utilities completed the acquisition of regulated natural gas distribution utility systems serving Columbus and Gainesville, Georgia (the "Columbus/Gainesville Gas System"). Consideration for the utility asset purchase was approximately U.S. $140.7 million plus working capital and closing adjustments for a total consideration of U.S. $153.0 million. The regulated natural gas distribution utilities provide natural gas service to approximately 64,000 total connections in Georgia.

U.S. Debt Private Placement

On July 31, 2013, Liberty Utilities issued U.S. $125.0 million of debt through a private placement. The financing is the third series of notes issued pursuant to Liberty Utilities' master indenture. The notes are senior unsecured with an average life maturity of ten years and a weighted average coupon of

3.81%. The proceeds of the private placement financing were used to repay the U.S. $105.0 million short term acquisition facility and reduce the drawn amount on Liberty's revolving credit facility.

Granite State Electric System Rate Case

On March 29, 2013, Granite State Electric System filed a rate case with the New Hampshire Public Service Commission seeking an increase in EBITDA of U.S. $13.2 million, and an additional U.S. $1.2 million increase in 2014 subject to the completion of certain capital projects. The filing is based on a 2012 test year, with revenues and expenses adjusted to reflect known and measurable changes. Among other things, Granite State Electric Company requested and received approval to continue the current cost-recovery tracking mechanism related to the Reliability Enhancement and Vegetation Management Plan and was granted an annual increase of $0.4 million starting July 1, 2013. Granite State Electric also requested a modification to allow for recovery of pre-staging personnel and equipment for qualifying storms. The case is expected to be concluded in mid-2014. In June 2013, Granite State received approval to implement interim rate tariffs which provide an annualized increase in revenues of $6.5 million and an expected increase in storm recovery costs, effective in November 2013, which provides an additional annualized revenue increase of $1.6 million.

Algonquin Power Co. Highlights

Construction Commencement of Cornwall Solar

During the quarter APCo began construction of the 10 MWac solar projected located near Cornwall, Ontario. The facility is the first solar project in APCo's portfolio and is expected to add 13,900 MW-hrs of production annually. Completion of construction is expected late in the fourth quarter of 2013.

Sale of Small U.S. Hydro Facilities

On March 14, 2013, APCo entered into an agreement to sell ten 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. $27 million. APCo closed the sale of nine of the ten facilities on June 28, 2013 for total proceeds of approximately $23.4 million with the tenth facility expected to be sold in Q4, 2013. The operating results from these facilities for current and prior periods are therefore disclosed as discontinued operations on the consolidated statements of operations.

Energy From Waste Facility

During the quarter, the Company conducted a strategic review of the Company's business plan and opportunities available for its Energy from Waste ("EFW") and Brampton Cogeneration Inc. ("BCI") facilities. The review concluded that EFW and BCI are no longer considered strategic to the ongoing operations of the Company and that management should pursue options to divest the facilities. The nets assets of the facilities have been written down to their estimated fair value less costs of sale which resulted in a one-time write down of $35.7 million, net of tax, in the second quarter of 2013. The operating results from these facilities are also disclosed as discontinued operations on the consolidated statements of operations and prior periods have been reclassified to conform to this presentation.

2013 Six months results from operations

Key Selected Six months Financial Information

	Six months ended June 30	
(millions of dollars except per share information)	**2013**	**2012**
Revenue	**$ 342.1**	$ 116.9
Adjusted EBITDA [1, 3]	**118.9**	43.4
Cash provided by operating activities	**52.7**	28.4
Adjusted funds from operations[1, 3]	**84.8**	29.6
Net earnings attributable to Shareholders from continuing operations	**36.2**	7.3
Net earnings attributable to Shareholders	**1.1**	8.3
Adjusted net earnings[1, 3]	**34.7**	11.8
Dividends declared to Common Shareholders	**33.3**	21.6

Key Selected Six months Financial Information (continued)

(millions of dollars except per share information)	Six months ended June 30 2013	2012
Weighted Average number of common shares outstanding	**202,802,827**	146,998,173
Per share		
Basic net earnings from continuing operations	**$ 0.18**	$ 0.05
Basic net earnings	**$ 0.01**	$ 0.06
Adjusted net earnings[1, 2, 3]	**$ 0.17**	$ 0.08
Diluted net earnings	**$ 0.01**	$ 0.06
Cash provided by operating activities [1, 2, 3]	**$ 0.26**	$ 0.19
Adjusted funds from operations[1, 2, 3]	**$ 0.42**	$ 0.20
Dividends declared to Common Shareholders	**$ 0.16**	$ 0.14
Total Assets	**3,201.8**	1,416.0
Total Liabilities[4]	**1,091.5**	461.8

[1] APUC uses adjusted EBITDA, adjusted net earnings and adjusted funds from operations to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.

[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] Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

[4] Long term debt includes current and long term portion of debt and convertible debentures.

For the six months ended June 30, 2013, APUC experienced an average U.S. exchange rate of approximately $1.0161 as compared to $0.9994 in the same period in 2012. As such, any period over period 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 six months ended June 30, 2013, APUC reported total revenue of $342.1 million as compared to $116.9 million during the same period in 2012, an increase of $225.2 million. The major factors resulting in the increase in APUC revenue in the six months ended June 30, 2013 as compared to the corresponding period in 2012 are set out as follows:

		Six months ended June 30, 2013 (Millions)
Comparative Prior Period Revenue		$ 116.9
Significant Changes:		
Liberty Utilities:		
West –	Implementation of decoupling mechanism and increased customer demand	3.1
Central –	Revenue increase due to Midwest Gas Systems, and Pine Bluff Water System acquisitions	48.3
East –	Additional revenue due to EnergyNorth Gas System, Granite State Electric System, and Columbus/Gainesville Gas System acquisitions	132.3
APCo:		
Renewable:		
	Acquisition of Sandy Ridge, Minonk, Senate and Shady Oaks Wind Facilities (collectively, the "U.S. Wind Facilities")	30.6
	Sale of Renewable Energy Credits generated from the U.S. Wind Facilities	2.5
	St Leon II Wind Facility – Revenue increase from expansion	1.8
Thermal:		
	Sanger Facility – Increase due to planned shutdown in 2012	3.1
Impact of the stronger U.S. dollar		3.9
Other		(0.4)
Current Period Revenue		$ 342.1

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

Adjusted EBITDA in the six months ended June 30, 2013 totalled $118.9 million as compared to $43.4 million during the same period in 2012, an increase of $75.5 million.

The increase in Adjusted EBITDA was primarily due to increased revenues from EnergyNorth Gas System, Granite State Electric System, Midwest Gas System, U.S. Wind Facilities, and Columbus/Gainesville Gas System acquisitions, and increased demand and higher rates at the Liberty Utilities (West)'s electric distribution utility. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings (see Non-GAAP Performance Measures).

For the six months ended June 30, 2013, net earnings attributable to Shareholders from continuing operations totalled $36.2 million as compared to $7.3 million during the same period in 2012, an increase of $28.9 million. Net income per share from continuing operations was $0.18 for the six months ended June 30, 2013, as compared to net income per share of $0.05 during the same period in 2012.

The increase in net earnings from continuing operations attributable to Shareholders for the six months ended June 30, 2013 was due to $65.0 million increased earnings from operating facilities, $0.9 million due to a stronger U.S. dollar, $0.8 million in increased interest, dividend and other income, $3.4 million in decreased acquisition costs, $2.5 million in increased gains from derivative instruments, and $6.4 million in decreased allocations of earnings to non-controlling interests as compared to the same period in 2012. These items were partially offset by $27.1 million increased depreciation and amortization expense, $2.3 million related to increased administration charges, $10.2 million in higher interest expense and $10.5 million in higher tax expense.

For the six months ended June 30, 2013, net earnings (including discontinued operations) attributable to Shareholders totalled $1.1 million as compared to $8.3 million during the same period in 2012, a decrease of $7.2 million and primarily due to the write down in the carrying value of the EFW and BCI Facilities of $35.7 million. Net income per share totalled $0.01 for the six months ended June 30, 2013, as compared to net income per share of $0.06 during the same period in 2012.

During the six months ended June 30, 2013, cash generated by operating activities totalled $52.7 million or $0.26 per share as compared to cash provided by operating activities of $28.4 million, or $0.19 per share during the same period in 2012. During the six months ended June 30, 2013, adjusted funds from operations totalled $84.8 million or $0.42 per share as compared to adjusted funds from operations of $29.6 million, or $0.20 per share during the same period in 2012. A more detailed analysis of these factors is presented within the reconciliation of Adjusted Funds from operations to cash flow from operations set out below (see Non-GAAP Performance Measures).

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.

2013 Three month results from operations

Key Selected Second Quarter Financial Information

	Three months ended June 30	
(millions of dollars except per share information)	**2013**	**2012**
Revenue	**$ 148.8**	$ 58.7
Adjusted EBITDA [1, 3]	**56.5**	22.2
Cash provided by operating activities	**57.4**	17.3
Adjusted funds from operations[1, 3]	**37.1**	18.5
Net earnings attributable to Shareholders from continuing operations	**15.8**	5.3
Net earnings attributable to Shareholders	**(18.1)**	6.1
Adjusted net earnings[1, 3]	**15.4**	6.5
Dividends declared to Common Shareholders	**17.4**	11.3
Weighted Average number of common shares outstanding	**204,908,701**	153,414,269
Per share		
Basic net earnings from continuing operations	**$ 0.08**	$ 0.03
Basic net earnings	**$ (0.09)**	$ 0.04
Adjusted net earnings[1, 2, 3]	**$ 0.08**	$ 0.04
Diluted net earnings	**$ (0.09)**	$ 0.04
Cash provided by operating activities [1, 2, 3]	**$ 0.28**	$ 0.11
Adjusted funds from operations[1, 2, 3]	**$ 0.18**	$ 0.11
Dividends declared to Common Shareholders	**$ 0.09**	$ 0.07

[1] APUC uses adjusted EBITDA, adjusted net earnings and adjusted funds from operations to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.

[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] Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

For the three months ended June 30, 2013, APUC experienced an average U.S. exchange rate of approximately $1.0235 as compared to $1.0101 in the same period in 2012. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the three months ended June 30, 2013, APUC reported total revenue of $148.8 million as compared to $58.7 million during the same period in 2012, an increase of $90.1 million. The major factors resulting in the increase in APUC revenue in the three months ended June 30, 2013 as compared to the corresponding period in 2012 are set out as follows:

		Three months ended June 30, 2013 (Millions)
Comparative Prior Period Revenue	**$**	58.7
Significant Changes:		
Liberty Utilities:		
West – Implementation of decoupling mechanism and increased customer demand		1.6
Central – Revenue increase due to Midwest Gas Systems, and Pine Bluff Water System acquisitions		16.0
East – Additional revenue due to EnergyNorth Gas System, Granite State Electric System, and Columbus/Gainesville Gas System acquisitions		52.2
APCo:		
Renewable:		
Hydro – Increased hydrology resources		0.6
Acquisition of US Wind Facilities		14.5
Sale of Renewable Energy Credits generated from the U.S. Wind Facilities		1.5
St Leon II Wind Facility – Revenue increase from expansion		0.9
Tinker/AES – Increased rates at AES and increased production at the Tinker Hydro facility		(1.4)
Thermal:		
Sanger Facility – Increase due to planned shutdown in 2012		1.3
Impact of the stronger U.S. dollar		2.6
Other		0.3
Current Period Revenue	**$**	148.8

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

Adjusted EBITDA in the three months ended June 30, 2013 totalled $56.5 million as compared to $22.2 million during the same period in 2012, an increase of $34.3 million.

The increase in Adjusted EBITDA was primarily due to increased revenues from EnergyNorth Gas System, Granite State Electric System, Midwest Gas System, U.S. Wind Facilities, and Columbus/Gainesville Gas System acquisitions, and increased demand and higher rates at the Liberty Utilities (West)'s electric distribution utility. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings (see Non-GAAP Performance Measures). A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings (see Non-GAAP Performance Measures).

For the three months ended June 30, 2013, net earnings attributable to Shareholders from continuing operations totalled $15.8 million as compared to $5.3 million during the same period in 2012, an increase of $10.5 million. Net income per share from continuing operations was $0.08 for the three months ended June 30, 2013, as compared to net income per share of $0.03 during the same period in 2012.

The increase in net earnings from continuing operations attributable to Shareholders for the three months ended June 30, 2013 was due to $27.9 million increased earnings from operating facilities, $0.7 million in increased interest, dividend and other income, $1.5 million in decreased acquisition costs, $1.2 million in increased gains from derivative instruments, $3.9 million in decreased allocations of earnings to non-controlling interests as compared to the same period in 2012. These items were partially offset by $14.2 million increased depreciation and amortization expense, $1.9 million related to increased administration charges, $6.7 million in higher interest expense and $1.9 million in higher tax expense.

For the three months ended June 30, 2013, net loss (including discontinued operations) attributable to Shareholders totalled $18.1 million as compared to net income attributable to Shareholders of $6.1 million during the same period in 2012, a decrease of $24.2 million, and predominantly due to the discontinuance of the EFW Facility. Net loss per share totalled $0.09 for the three months ended June 30, 2013, as compared to net income per share of $0.04 during the same period in 2012.

During the three months ended June 30, 2013, cash generated by operating activities totalled $57.4 million or $0.28 per share as compared to cash provided by operating activities of $17.3 million, or $0.11 per share during the same period in 2012. During the three months ended June 30, 2013, adjusted funds from operations totalled $37.1 million or $0.18 per share as compared to adjusted funds from operations of $18.5 million, or $0.11 per share during the same period in 2012. A more detailed analysis of these factors is presented within the reconciliation of Adjusted Funds from operations to cash flow from operations set out below (see Non-GAAP Performance Measures).

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.

Outlook

APUC expects operational results for power generation in the third quarter of 2013 to reflect long-term average resource conditions for hydroelectric and wind power generation. Third quarter results will also continue to reflect growth from the acquisition of its newly acquired U.S. wind farms.

APUC expects continuing modest customer growth throughout its regulated utilities service territories in 2013 and that utility operations will meet APUC's expectations for the third quarter of 2013. Third quarter results will also continue to reflect the acquisition of the Columbus/Gainesville Gas System on April 1, 2013, the Pine Bluff Water System on February 1, 2013.

Algonquin

APCo: Renewable Energy Division

	Long Term Average Resource	Three months ended June 30		Long Term Average Resource	Six months ended June 30	
		2013	2012		2013	2012
Performance (GW-hrs sold)						
Hydro Facilities:						
Ontario[7]	**35.8**	**16.5**	**31.2**	**72.9**	**24.4**	67.8
Quebec	**83.4**	**88.9**	**83.8**	**141.0**	**151.5**	147.4
Maritime	**72.3**	**68.6**	**58.6**	**108.0**	**109.9**	93.9
Western	**19.0**	**19.7**	**20.5**	**28.6**	**29.3**	30.3
	210.5	**193.7**	**194.1**	**350.5**	**315.1**	339.4
Wind Facilities:						
Manitoba	**99.5**	**105.7**	**101.8**	**220.9**	**209.9**	214.9
Saskatchewan[1]	**20.8**	**20.4**	**21.2**	**43.9**	**41.3**	45.1
Pennsylvania[2]	**37.7**	**35.3**	**-**	**84.8**	**80.1**	-
Illinois[3]	**271.7**	**242.2**	**-**	**582.1**	**526.0**	-
Texas[4]	**137.4**	**155.0**	**-**	**288.6**	**300.3**	-
	567.1	**558.6**	**123.0**	**1,220.3**	**1,157.6**	260.0
Total	**777.6**	**752.3**	**317.1**	**1,570.8**	**1,472.7**	599.4

	Long Term Average Resource	Three months ended June 30 2013	2012	Long Term Average Resource	Six months ended June 30 2013	2012
Revenue[5]		**(millions)**	(millions)		**(millions)**	(millions)
Energy sales		**$ 37.0**	$ 22.3		**$ 76.7**	$ 43.8
Less:						
Cost of Sales – Energy[6]		**(1.1)**	(2.5)		**(3.5)**	(4.1)
Net Energy Sales		**$ 35.9**	$ 19.8		**$ 73.2**	$ 39.7
Other Revenue		**1.9**	0.5		**2.7**	0.8
Total Net Revenue		**$ 37.8**	$ 20.3		**$ 75.9**	$ 40.5
Operating expenses		**(9.5)**	(5.0)		**(18.4)**	(10.4)
Interest and Other income		**0.6**	0.6		**0.9**	1.0
HLBV Income		**7.5**	-		**12.6**	-
Division operating profit		**$ 36.4**	$ 15.9		**$ 71.0**	$ 31.1

[1] 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.
[2] Represents the operations of Sandy Ridge Wind Facility which was acquired on July 1, 2012.
[3] Represents the operations of Minonk and Shady Oaks Wind Facilities acquired on December 10, 2012, and January 1, 2013, respectively. Production at the Shady Oaks Facility has been subject to congestion related curtailment by the independent system operator but where compensation is expected to be received for lost energy sales.
[4] Represents the operations of Senate Wind Facility acquired on December 10, 2012.
[5] While most of APCo's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division, as compared to the same period in the prior year.
[6] 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 interim consolidated Financial Statements, these amounts are included in operating expenses.
[7] APCo's Long Sault hydro facility was offline during most of the first half of 2013. See below for additional commentary.

2013 Six Month Operating Results

Production data, revenue and expenses have been adjusted to remove the results of the New York and New England regional assets which are now disclosed as discontinued operations. See Financial Statement note 15 for details.

For the six months ended June 30, 2013, the Renewable Energy Division produced 1,472.7GW-hrs of electricity, as compared to 599.4 GW-hrs produced in the same period in 2012, an increase of 146%. The increased generation is primarily due to the acquisition of Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities. This level of production represents sufficient renewable energy to supply the equivalent of 162,700 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 805,327 tons of CO_2 gas was prevented from entering the atmosphere in the first six months of 2013.

Adjusting for the effect of the unplanned outage at APCo's Long Sault generating station, during the six months ended June 30, 2013, the division generated electricity equal to 97% of long-term projected average resources (wind and hydrology) as compared to 101% during the same period in 2012. In the first six months of 2013, the Ontario region's operating facilities produced 10% above long-term average resources, while Quebec, Maritimes, Western and Texas regions produced 2% to 8% higher than long-term average resources. The Manitoba, Saskatchewan, Pennsylvania and Illinois regions experienced resources slightly lower than long-term average resources, producing 5% to 10% below long-term average resources.

For the six months ended June 30, 2013, revenue from energy sales in the Renewable Energy Division totalled $76.7 million, as compared to $43.8 million during the same period in 2012. As the purchase of energy by the Energy Services Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the six months ended June 30, 2013, net revenue from energy sales in the Renewable Energy Division totalled $73.2 million, as compared to $39.7 million during the same period in 2012.

Revenue from generation at APCo's hydro facilities located in the Ontario, Quebec and Western regions decreased by $3.1 million primarily as a result of the Long Sault facility's unplanned shutdown in the Ontario region offset by a 1% increase in weighted average energy rates as compared to the same period in 2012. Lost production from the unplanned shutdown at the Long Sault generating facility in Ontario was largely covered by business interruption insurance claim proceeds in the amount of $3.4 million. Further recognition of revenue under APCo's business interruption insurance policy will not occur until final settlement of the claim expected in the fourth quarter. Revenue from APCo's hydro facility located in the Maritime region decreased by $0.2 million primarily due to a $0.8 million decrease in weighted average energy rates offset by a $0.5 million increase in production, as compared to the same period in 2012.

Revenue from APCo's wind facilities located in the Manitoba region increased $1.5 million due primarily to $1.8 million from the expansion of St. Leon wind facility, offset partially by $0.3 million in lower wind resources at St. Leon wind facility. APCo's wind facilities located in the Pennsylvania, Texas, and Illinois regions consists of Sandy Ridge, Minonk, Senate and Shady Oaks Wind Facilities, acquired in 2012 and 2013, and produced revenue of $31.1 million.

Revenue at AES increased $0.3 million or 3% primarily due to a $0.5 million increase in weighted average energy rates partially offset by $0.2 million of decreased 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 six months ended June 30, 2013, energy purchase costs by AES totalled $3.5 million as compared to $4.1 million during the same period in 2012, a decrease of $0.6 million. AES' decreased energy purchase costs for the six months ended June 30, 2013 was primarily due to a lower volume of energy purchases from external suppliers, partially offset by higher average prices. During this period, AES purchased approximately 33.9 GW-hrs of energy at market and fixed rates averaging U.S. $103 per MW-hr. During the six months, the Maritime region generated approximately 74% of the energy required to service its customers as well as AES' customers, as compared to 53% in the same period in 2012.

For the six months ended June 30, 2013, other revenue totalled $2.7 million, as compared to $0.8 million in the same period in 2012, representing an increase of $1.9 million. The increase is primarily attributed to Renewable Energy Credit (REC) revenue earned at the Minonk and Sandy Ridge wind facilities.

The Red Lily I wind farm located in Saskatchewan produced 41.3 GW-hrs of electricity for the six months ended June 30, 2013. 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 Red Lily I for a direct 75% equity interest in 2016. For the six months ended June 30, 2013, APCo earned fees and interest payments from Red Lily in the total amount of $1.2 million.

For the six months ended June 30, 2013, operating expenses excluding energy purchases totalled $18.4 million, as compared to $10.4 million during the same period in 2012, an increase of $8.0 million. The higher expenses were primarily due to the newly acquired Sandy Ridge, Senate, Minonk, and Shady Oaks Wind Facilities partially offset by lower lease and water usage costs at the Long Sault and Cote St. Catherine hydro facilities.

For the six months ended June 30, 2013, interest and other income totalled $0.9 million, consistent with the same period in 2012. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I. This amount is included as part of APCo's earnings from its investment in Red Lily I, as discussed above.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of the net tax attributes 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 first six months amounted to approximately U.S. $12.6 million.

For the six months ended June 30, 2013, the Renewable Energy Division's operating profit totalled $71.0 million, as compared to $31.1 million during the same period in 2012, representing an increase of $39.9 million. Operating profit increased $0.4 million as a result of the stronger U.S. dollar's impact on the division's U.S. operations.

2013 Second Quarter Operating Results

For the quarter ended June 30, 2013, the Renewable Energy Division produced 752.3 GW-hrs of electricity, as compared to 317.1 GW-hrs produced in the same period in 2012, an increase of 137%. The increased generation is primarily due to the acquisition of Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities. This level of production represents sufficient renewable energy to supply the equivalent of 165,300 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 409,100 tons of CO_2 gas was prevented from entering the atmosphere in the second quarter of 2013.

Adjusting for the effect of the unplanned outage at APCo's Long Sault generating station, during the quarter ended June 30, 2013, the division enjoyed the benefit of geographic and modality diversification with generated electricity equal to 99% of long-term projected average resources (wind and hydrology) as compared to 99% during the same period in 2012. In the second quarter of 2013, the Ontario region's operating facilities produced 18% above long-term average resources. Quebec, Manitoba, Western and Texas regions produced 4% to13% higher than long-term average resources. The Maritimes, Saskatchewan, and Pennsylvania regions experienced resources slightly lower than long-term average resources, producing 2% to 6% below long-term average resources. The Illinois region produced 11% below long-term average resources with Minonk producing 162.1 GWhrs in the second quarter.

For the quarter ended June 30, 2013, revenue from energy sales in the Renewable Energy Division totalled $37.0 million, as compared to $22.3 million during the same period in 2012. As the purchase of energy by the Energy Services Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the quarter ended June 30, 2013, net revenue from energy sales in the Renewable Energy Division totalled $35.9 million, as compared $19.8 million during the same period in 2012.

Revenue from generation at APCo's hydro facilities located in the Ontario, Quebec and Western regions decreased by $0.1 million due to an 8% decrease in production primarily a result of the Long Sault facility's unplanned shutdown in the Ontario region offset by an 8% increase in weighted average energy rates as compared to the same period in 2012. Revenue associated with lost production from the unplanned shutdown at the Long Sault generating facility in Ontario was partially reimbursed through business interruption insurance claim proceeds in the amount of $0.6 million. Further recognition of revenue reimbursement under APCo's business interruption insurance policy will not occur until final settlement of the claim expected in the fourth quarter. Revenue from APCo's hydro facility located in the Maritime region decreased $0.2 million primarily due to a $0.4 million decrease in weighted average energy rates, partially offset by $0.2 million increase in production.

Revenue from APCo's wind facilities located in the Manitoba region increased $0.7 million due primarily to $0.9 million from the expansion of St. Leon II wind facility, offset partially by $0.2 million in lower wind resources at St. Leon wind facility. Revenue from APCo's wind facilities located in the Pennsylvania, Texas, and Illinois regions which are comprised of the US Wind Facilities acquired in 2012 and 2013, produced revenue of $14.8 million.

Revenue at AES decreased $1.1 million primarily due to a $0.8 million reclassification of intercompany energy/steam sales to the Thermal Division relating to the first quarter 2013 and $0.3 million due to decreased average energy rates. 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 June 30, 2013, energy purchase costs by AES totalled $1.1 million as compared to $2.5 million during the same period in 2012, a decrease of $1.4 million. AES' decreased energy purchase costs for the quarter ended June 30, 2013 was primarily due to a lower volume of energy purchases from external suppliers, partially offset by higher average prices. During this period, AES purchased approximately 12.2 GW-hrs of energy at market and fixed rates averaging U.S. $92 per MW-hr. During the quarter, the Maritime region generated approximately 84% of the load required to service its customers as well as AES' customers, as compared to 59% in the same period in 2012.

For the quarter ended June 30, 2013, other revenue totalled $1.9 million, as compared to $0.5 million in the same period in 2012, representing an increase of $1.4 million. The increase is primarily attributed to Renewable Energy Credit (REC) revenue earned at the Minonk and Sandy Ridge wind facilities.

The Red Lily I wind farm located in Saskatchewan produced 20.4 GW-hrs of electricity for the quarter ended June 30, 2013. 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 Red Lily I for a direct 75% equity interest in 2016. For the quarter ended June 30, 2013, APCo earned fees and interest payments from Red Lily in the total amount of $0.8 million.

For the quarter ended June 30, 2013, operating expenses excluding energy purchases totalled $9.5 million, as compared to $5.0 million during the same period in 2012, an increase of $4.5 million. The increase was primarily driven by the increase in costs as a result of the newly acquired Sandy Ridge, Senate, Minonk, and Shady Oaks Wind Facilities.

For the quarter ended June 30, 2013, interest and other income totalled $0.6 million, consistent with the same period in 2012. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I. This amount is included as part of APCo's earnings from its investment in Red Lily I, as discussed above.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of net tax attributes generated by APCo in the period from certain of its U.S. wind power generation facilities. The value of net tax attributes recognized in the second quarter amounted to approximately U.S. $7.5 million.

For the quarter ended June 30, 2013, the Renewable Energy Division's operating profit totalled $36.4 million, as compared to $15.9 million during the same period in 2012, representing an increase of $20.5 million. Operating profit increased $0.3 million as a result of the stronger U.S. dollar's impact on the division's U.S. operations.

APCo: Thermal Energy Division

	Six months ended June 30, 2013			Six months ended June 30, 2012		
	Windsor Locks	**Sanger**	**Total**	**Windsor Locks**	**Sanger**	**Total**
Performance (GW-hrs sold)	**57.9**	**66.9**	**124.8**	**119.0**	**29.6**	**148.6**
Performance (steam sales – billion lbs)	**345.4**		**345.4**	**300.6**		**300.6**
(all amounts in millions)						
Revenue						
Energy/steam sales	**$ 9.5**	**$ 7.3**	**$ 16.8**	$ 9.4	$ 4.4	$ 13.8
Less:						
Cost of Sales – Fuel	**(6.1)**	**(2.9)**	**(9.0)**	**(6.3)**	**(0.7)**	**(7.0)**
Net Energy/Steam Sales	**$ 3.4**	**$ 4.4**	**$ 7.8**	$ **3.1**	$ **3.7**	$ **6.8**
Other revenue	**0.3**	**0.8**	**1.1**	**-**	**0.5**	**0.5**
Total net revenue	**$ 3.7**	**$ 5.2**	**$ 8.9**	$ **3.1**	$ **4.2**	$ **7.3**
Expenses						
Operating expenses	**(2.5)**	**(2.7)**	**(5.2)**	**(2.7)**	**(1.7)**	**(4.4)**
Facility operating profit	**1.2**	**$ 2.5**	**$ 3.7**	$ **0.4**	$ **2.5**	$ **2.9**
Interest and other income			**(0.2)**			**0.5**
Divisional operating profit			**$ 3.5**			$ **3.4**

APCo's Sanger and Windsor Locks generation 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 facility and regional changes in the average landed cost for natural gas may result in one facility showing increasing costs per unit while the other shows decreasing costs, as 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.

2013 Six Month Operating Results

Production data, revenue and expenses have been adjusted to remove the results of the EFW Facility which are now disclosed as discontinued operations. See Financial Statement note 15 for details.

For the six months ended June 30, 2013, the Thermal Energy Division produced 124.8 GW-hrs of energy as compared to 148.6 GW-hrs of energy in the comparable period of 2012. The decrease in energy production was due primarily to the installation of the new Titan turbine which is a smaller, more efficient turbine, sized to optimize the energy and steam requirements of the steam host, and to minimize exposure of the facility to the ISO NE electricity market, compared to the larger Frame 6 turbine that was operating in previous years.

This is partially offset by an increased production at Sanger as a result of a planned outage during the six month ended June 30, 2012.

For the six months ended June 30, 2013, the Thermal Division's operating profit was $3.5 million, which was consistent with the same period in 2012. The Windsor Locks facility contributed $1.2 million, while the Sanger facility contributed $2.5 million of operating profit during the six months ended June 30, 2012 as compared to $0.4 million and $2.5 million, respectively, during the same period in the prior year. Operating profit increased $0.2 million as a result of the stronger U.S. dollar's impact on the division's U.S. operations. Detailed results of each facility are described below.

Windsor Locks

For the six months ended June 30, 2013, the Windsor Locks facility sold 345.4 billion lbs of steam as compared to 300.6 billion lbs of steam in the comparable period of 2012.

Energy/Steam revenues at the Windsor Locks facility were $9.5 million as compared to $9.4 million in the same period in 2012. The increase in electricity/steam sales is attributed to a higher average price for gas and higher steam production driven by increased customer demand, partially offset by the lower electrical energy production as a result of the newly installed, smaller, more efficient Titan turbine. Natural gas costs for the period were $6.1 million as compared to $6.3 in the same period in 2012. The decrease in natural gas costs is due to a $2.1 million decrease in the volume of gas consumed as a result of the newly installed, smaller Titan turbine offset by a $1.9 million increase in the average landed cost of natural gas. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as an appropriate measure of the division's results. For the six months ended June 30, 2013, net energy / steam sales revenue at the Windsor Locks facility totalled $3.4 million, as compared to $3.1 million during the same period in 2012, an increase of $0.3 million. Operating expenses, excluding natural gas costs were $2.5 million as compared to $2.7 million in the same period in 2012. The decrease in operating expenses was primarily due to the reduced electricity purchases. In 2012, during the planned shutdown, the Windsor Locks facility was required to purchase all the electricity requirements for its customers; this additional expense was not required in the current year. The Windsor Locks facility's resulting net operating income for the six months ended June 30, 2013 was $1.2 million as compared to $0.4 million in the same period in 2012, an increase of $0.8 million.

Sanger

The Sanger facility's operating profit was driven by electrical/thermal energy sales of $7.3 million as compared to $4.4 million in the same period in 2012, an increase of $2.9 million. The increase in electrical/thermal energy is primarily a result of the Sanger facility being offline due to a planned outage for three months during the same period in the prior year. The return to operation resulted in an increase of $1.3 million due to increased electrical energy production, and $1.6 million in increased billing rates, as compared to the same period in 2012. Capacity revenues remained unchanged at $3.3 million. Gas costs for the period were $2.9 million as compared to $0.7 million in the same period in 2012. The increase in gas costs is due to an increase in the volume of natural gas consumed, and a 78% increase in the average cost of natural gas per MMBTU. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (electricity/thermal energy sales revenue less natural gas expense) as an appropriate measure of the division's results. For the six months ended June 30, 2013, net electricity/thermal energy sales revenue at the Sanger facility totalled $4.4 million, as compared to $3.7 million during the same period in 2012, an increase of $0.7 million. Operating expenses, excluding natural gas costs were $2.7 million as compared to $1.7 million in the same period in 2012. The increase in operating expenses was due to the Sanger Facility operating for the six months ended June 30, 2013, as opposed to being offline for three months during the same period in 2012. The Sanger facility's resulting net operating income for the six months ended June 30, 2013 was $2.5 million, as compared to $2.5 million during the same period in 2012.

2013 Second Quarter Operating Results

	Three months ended June 30, 2013			Three months ended June 30, 2012		
	Windsor Locks	Sanger	Windsor Total	Locks	Sanger	Total
Performance						
(GW-hrs sold)	**27.9**	**32.7**	**60.6**	**38.6**	**24.6**	**63.2**
Performance						
(steam sales – billion lbs)	**145.2**		**145.2**	**132.4**		**132.4**
(all amounts in millions)						
Revenue						
Energy/steam sales	**$ 5.0**	**$ 4.7**	**$ 9.7**	$ **4.2**	$ **3.3**	$ **7.5**
Less:						
Cost of Sales – Fuel	**(2.5)**	**(1.5)**	**(4.0)**	**(2.4)**	**(0.6)**	**(3.0)**
Net Energy/Steam Sales Revenue	**$ 2.5**	**$ 3.2**	**$ 5.7**	$ **1.8**	$ **2.7**	$ **4.5**
Other revenue	**0.1**	**0.4**	**0.5**		**0.4**	**0.4**
Total net revenue	**$ 2.6**	**$ 3.6**	**$ 6.2**	$ **1.8**	$ **3.1**	$ **4.9**
Expenses						
Operating expenses	**(1.2)**	**(1.5)**	**(2.7)**	**(1.7)**	**(0.9)**	**(2.6)**
Facility operating profit	**$ 1.4**	**$ 2.1**	**$ 3.5**	$ **0.1**	$ **2.2**	$ **2.3**
Interest and other income			**(0.5)**			**0.2**
Division operating profit			**$ 3.0**			**$ 2.5**

Production data, revenue and expenses have been adjusted to remove the results of the EFW facility which is now disclosed as discontinued operations. See Financial Statement note 15 for details

For the three months ended June 30, 2013, the Thermal Energy Division produced 60.6 GW-hrs of electrical energy as compared to 63.2 GW-hrs of electrical energy in the comparable period of 2012. The decrease in electrical energy production at the Windsor Locks facility was primarily due to the installation of the new Titan turbine which is a smaller, more efficient turbine, sized to optimize the electricity and steam requirements of the steam host, and to minimize exposure of the facility to the ISO NE electricity market, compared to the larger Frame 6 turbine that was operating in previous years. During the same period, Sanger experienced increased production as a result of a planned outage being offline for 22 days during the same period of 2012.

For the three months ended June 30, 2013, the Thermal Division's operating profit was $3.0 million as compared to $2.5 million in the same period in 2012, an increase of $0.5 million. The Windsor Locks facility contributed $1.4 million, while the Sanger facility contributed $2.1 million of operating profit during the three months ended June 30, 2013 as compared to $0.1 million and $2.2 million, respectively during the same period in the prior year. Operating profit increased $0.1 million as a result of the stronger U.S. dollar's impact on the division's U.S. operations. Detailed results of each facility are described below.

Windsor Locks

For the three months ended June 30, 2013, the Windsor Locks facility sold 145.2 billion lbs of steam as compared to 132.4 billion lbs of steam in the comparable period of 2012.

The Windsor Locks facility's operating profit was driven by electricity/steam sales of $5.0 million as compared to $4.2 million in the same period in 2012. The increase in electricity/steam sales is primarily a result of a $0.8 million reclassification of intercompany electricity/steam sales from the Renewable Energy Division relating to the first quarter of 2013. Gas costs for the period were $2.5 million as compared to $2.4 million in the same period in 2012. The increase in gas costs is a result of a 3% increase on the average landed cost of natural gas per MMBTU offset by a 2% decrease in the volume of natural gas consumed, as compared to the same period in 2012. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as an appropriate measure of the division's results. For the three months ended June 30, 2013, net electrical energy / steam sales revenue at the Windsor Locks facility totalled $2.5 million, as compared to $1.8 million during the same period in 2012, an increase of $0.7 million. Operating expenses, excluding natural gas costs were $1.2 million as compared to $1.7 million in the same period in 2012. The decrease in operating expenses was primarily due to the reduced electricity purchases. In 2012 during the planned shutdown Windsor Locks was required to purchase all the electricity requirements for its customers; this additional expense was not required in the current year. The Windsor Locks facility's resulting net operating income for the three months ended June 30, 2013 was $1.4 million as compared to $0.1 million in the same period in 2012, an increase of $1.3 million.

Sanger

The Sanger facility's operating profit was driven by electricity/thermal energy sales of $4.7 million as compared to $3.3 million in the same period in 2012. The $1.4 million increase in electricity/thermal energy sales is attributed to increased production primarily as a result of a planned outage for 22 days during the three months ended June 30 2012. The return to operation resulted in $1.2 million in increased energy production, in addition to $0.2 million in increased billing rates as compared to the same period in 2012. Capacity revenues remained unchanged at $2.4 million. Gas costs for the period were $1.5 million as compared to $0.6 million in the same period in 2012. The increase in gas costs is due to an increase in the volume of natural gas consumed, and a 103% increase in the average cost of natural gas per MMBTU as compared to the same period in 2012. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (electricity/thermal energy sales revenue less natural gas expense) as an appropriate measure of the division's results. For the three months ended June 30, 2013, net electricity/ thermal energy sales revenue at the Sanger facility totalled $3.2 million, as compared to $2.7 million during the same period in 2012, an increase of $0.5 million. Operating expenses, excluding natural gas costs were $1.5 million as compared to $0.9 million in the same period in 2012. The increase in operating expenses was due to the facility operating for the full quarter in 2013. The Sanger facility's resulting net operating income for the three months ended June 30, 2013 was $2.1 million as compared to $2.2 million in the same period in 2012, a decrease of $0.1 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.

Projects Currently in Development

APCo's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of power purchase agreements ("PPA"). The projects are as follows:

Project Name	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GW-hrs
Chaplin Wind [1]	Saskatchewan	177	$355.0	2016	25	720.0
Amherst Island [2]	Ontario	75	$230.0	2015	20	247.0
Val Eo [1]	Quebec	24	$70.0	2015	20	66.0
Morse Wind [3, 4]	Saskatchewan	23	$70.0	2015	20	93.0
St. Damase [1]	Quebec	24	$66.0	2014	20	78.7
Cornwall Solar [1, 2]	Ontario	10	$45.0	2013	20	13.4
Total		**333**	**$836.0**			**1,218.1**

Notes:
1. PPA signed
2. FIT contract awarded
3. Two 10 MW PPAs; one 5 MW PPA
4. Comprised of three projects that are connected geographically and will be built simultaneously. All three projects were awarded PPAs under the province's Green Options Partner Program ("GOPP").

Project development updates for the quarter

A full description of APCo's contracted development projects is contained in APUC's annual MD&A. The following discussion provides updates on significant matters related to those projects.

Cornwall Solar

The Cornwall Project is a 10 MWac solar project located near Cornwall, Ontario. The project has been granted an Ontario FIT contract by the OPA, with a 20 year term and a rate of $443/MW-hr, resulting in expected initial annual revenues of approximately $6.2 million. Total capital cost of the project is targeted at approximately $45 million, including the consideration to be paid for the acquisition of the project. The project received its Renewable Energy Approval on January 15th, 2013, and its Notice to Proceed on April 29, 2013.

Construction of the project began during the quarter with completion of construction expected late in fourth quarter of 2013 with expected annual generation of approximately 13,912 MW-hrs.

Chaplin Wind

Chaplin Wind Project is a 177MW facility located west of Moose Jaw Saskatchewan. The project has a signed 25 year PPA with SaskPower. The capital cost of the project is targeted at $355 million.

APCo expects to submit the initial Environmental Impact Assessment to Environmental Assessment Branch, Saskatchewan Environment in Q3 2013. The Environmental Assessment Branch will determine if a full Environmental Impact Assessment is required. The initial Environmental Impact Assessment contains the majority of the information and studies required in a full Environmental Impact Assessment.

Amherst Island Wind

Amherst Island Wind Project is a 75MW facility located in Prince Edward County Ontario. The project has a signed 20 year PPA with the Ontario Power Authority. The capital cost of the project is targeted at $230 million.

The Renewable Energy Approval ("REA") application was submitted in April 2013, with an anticipated approval date to be received late in the fourth quarter of 2013. Subject to receipt of the REA, construction would commence shortly thereafter, with an expected construction completion timeframe of 12 to 18 months.

Morse Wind Project

Morse Wind Project is a 23MW facility located near Morse, Saskatchewan, approximately 180 km west of Regina. The project has a signed 20 year PPA with SaskPower. The capital cost of the project is targeted at $70 million, inclusive of acquisition costs.

The provincial permitting of the site was completed in the first quarter of 2013 and submitted to the provincial Environmental Assessment agency. In April 2013 the project was deemed a "non-development" by the Provincial Environmental Assessment Branch thereby not requiring further environmental assessment review.

Saint-Damase Wind Project

Saint-Damase Wind Project is a 24MW facility located near St. Damase, Quebec in a partnership 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 $66 million. On June 25, 2013, the partnership executed an interconnection agreement with Hydro Quebec. The permitting and the environmental impact assessment are ongoing and the construction of the first project phase is to begin in the fall of 2013, with commercial operation for the project expected to commence in late 2014.

The project's social acceptance is strong and there will be no requirement for a public hearing under the auspices of the Bureau d'audiences publiques sur l'environnement ("BAPE"). The environmental impact assessment for the project has also been submitted and is under review with provincial ministerial approval anticipated for the third quarter of 2013.

Val-Éo Wind Project

The Val-Éo Wind Project is a 24MW facility located in the local municipality of Saint-Gideon de Grandmont in a partnership with the Val-Éo wind cooperative formed by community based landowners. The Val-Éo Wind Project has signed a 20 year PPA with Hydro Quebec and has projected capital costs of $70 million. Preliminary permitting began in early 2011 and studies of flora and fauna are ongoing. The project received constructive comments during the open-house held on June 4, 2013 and anticipates the submission of the environmental impact study to the Minister of Sustainable Development, Environment, Wildlife and Parks in Q3 of 2013.

APCo Outlook

The APCo Renewable Energy Division is expected to perform based on long-term average resource conditions for both wind and hydrology in the third quarter of 2013. In October 2012, APCo's hydroelectric generating facility at Long Sault experienced an unplanned shut down. Three of four units at the facility were returned to service in the second quarter of 2013, with the final unit expected to return to full service during the third quarter of 2013. APCo expects its business interruption insurance to continue coverage for the lost revenue until the facility returns to full service. However, further recognition of revenue under APCo's business interruption insurance policy will not occur until final settlement of the insurance claim expected in the fourth quarter. The acquisition of an interest in the Minonk and Senate Wind Facilities (on December 10, 2012), and the Shady Oaks Wind Facility (on January 1, 2013) are expected to contribute additional revenue in 2013.

Windsor Locks will operate in line with quarterly performance from the latter half of 2012. Sanger is expected to operate in line with historic performance.

During the quarter, the Company conducted a strategic review of the Company's business plan and opportunities available for its Energy From Waste ("EFW") and Brampton Cogeneration Inc. ("BCI") facilities. The review concluded that EFW and BCI are no longer considered strategic to the ongoing operations of the Company and that management should look to divest the facilities. Accordingly, the assets of EFW are presented as assets held for sale on the unaudited interim Balance Sheet. In the second quarter of 2013, the nets assets of EFW were written down to their estimated fair value less cost of sale which resulted in a one-time write down of the net assets of $35.7 million, net of tax of $11.9 million. On June 28, 2013, APCo divested of nine 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. $27 million. A tenth U.S. hydroelectric generating facility is expected to be sold in Q4, 2013. The operating results from these facilities are therefore disclosed as discontinued operations on the consolidated statements of operations and prior periods have been reclassified to conform to this presentation.

Liberty Utilities

Liberty Utilities is a nationally diversified utility providing rate regulated electricity, natural gas, water distribution and wastewater collection utility services in the U.S. Liberty Utilities' strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The business focuses on driving maximum results by building constructive regulatory and customer relationships, and enhancing community connections.

	June 30, 2013		June 30, 2012	
Utility System Type	**Regulatory Assets**	**Connections**	**Regulatory Assets**	**Connections**
	U.S. $ (millions)		U.S. $ (millions)	
Electricity	$ 261.9	90,630	$ 159.0	46,955
Natural Gas	554.9	223,050	-	-
Water and Wastewater	235.5	96,650	202.9	76,800
	$ 1,052.3	410,330	$ 361.9	123,755

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

The Liberty Utilities (West) region is currently comprised of regulated electrical and water distribution and wastewater collection utility systems and serves approximately 115,000 active 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 110,000 active connections in the states of Arkansas, Texas, Missouri, Illinois, and Iowa.

Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems and serves approximately 186,000 active connections located in the states of New Hampshire and Georgia.

For electricity and natural gas operations, Liberty Utilities reports active connections, exclusive of vacant connections rather than total connections. For water and wastewater operations, Liberty Utilities reports total connections, inclusive of vacant connections.

Liberty Utilities: West Region

	Six months ended June 30 2013	2012
Average Number of Active Electric Connections		
Residential	40,800	41,350
Commercial – Small	5,440	5,510
Commercial – Large	54	54
Total Average Active Electric Connections	**46,294**	**46,914**
Average Number of Water Connections		
Wastewater connections	32,000	31,050
Water distribution connections	34,970	34,120
Total Average Water Connections	**66,970**	**65,170**
Customer Usage (GW-hrs)		
Residential	146.2	141.7
Commercial – Small	77.8	73.8
Commercial – Large	56.8	59.4
Total Customer Usage (GW-hrs)	**280.8**	**274.9**
Gallons Provided		
Wastewater treated (millions of gallons)	860	830
Water sold (millions of gallons)	2,210	2,270
Total Gallons Provided	**3,070**	**3,100**

Liberty Utilities (West)'s increase in average water and wastewater connections during the period is primarily due to development within the service territory. During the six months ended June 30, 2013, Liberty Utilities (West) provided approximately 2,210 million gallons of water to its customers and treated approximately 860 million gallons of wastewater as compared to 2,270 million gallons of water and 830 million gallons of wastewater during the same period in 2012.

For the six months ended June 30, 2013, electricity usage at Liberty Utilities (West)'s electric utility (Calpeco Electric System) totalled 280.8 GW-hrs, as compared to 274.9 GW-hrs for the same period in 2012, an increase of 5.9 GW-hrs or 2%. This increase in usage was primarily due to colder weather in the first quarter of 2013 as compared to the warmer weather experienced in the same period a year ago. Under the base rate revenue decoupling mechanism approved by the California Public Utilities Commission ("CPUC"), which became effective on January 1, 2013, 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, 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 Calpeco Electric System's customers according to their consumption.

	Six months ended June 30		Six months ended June 30	
	2013 U.S. $ (millions)	2012 U.S. $ (millions)	**2013 Can $ (millions)**	2012 Can $ (millions)
Water Assets for regulatory purposes	**182.9**	179.9		
Electricity Assets for regulatory purposes	**168.2**	159.0		
Revenue				
Utility electricity sales and distribution	**$ 38.0**	$ 35.1	**$ 38.6**	$ 35.3
Wastewater treatment	**9.0**	8.7	**9.2**	8.8
Water distribution	**9.3**	9.3	**9.4**	9.3
Total Revenue	**$ 56.3**	$ 53.1	**$ 57.2**	$ 53.4
Less:				
Cost of Sales – Electricity	**(19.5)**	(21.4)	**(19.8)**	(21.4)
	$ 36.8	$ 31.7	**$ 37.4**	$ 32.0
Expenses				
Operating expenses	**(17.8)**	(17.6)	**(18.3)**	(17.7)
Other income	**0.9**	0.8	**0.9**	0.8
Divisional operating profit	**$ 19.9**	$ 14.9	**$ 20.0**	$ 15.1

2013 Six Months Operating Results

Liberty Utilities (West) has investments in water and wastewater distribution assets for regulatory purposes of U.S. $182.9 million and electricity assets for regulatory purposes of U.S. $168.2 million as at June 30, 2013, as compared to U.S. $179.9 million and U.S. $159.0 million, respectively as at June 30, 2012.

For the six months ended June 30, 2013, Liberty Utilities (West)'s revenue totalled U.S. $56.3 million as compared to U.S. $53.1 million during the same period in 2012, an increase of U.S. $3.2 million or 6%.

For the six months ended June 30, 2013, Liberty Utilities (West)'s revenue from utility electricity sales totalled U.S. $38.0 million as compared to U.S. $35.1 million during the same period in 2012, an increase of U.S. $2.9 million or 8%. This increase in revenues was primarily due to an increase in base revenue requirement approved in the most recent rate case that became effective January 1, 2013 and milder winter and spring weather that occurred in the first part of 2012. The purchase of electricity by Liberty Utilities (West) is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, Liberty Utilities (West) compares 'net utility electricity sales' (utility electricity sales less fuel and purchased power costs) as a more appropriate measure of the division's results. For the six months ended June 30, 2013, net utility electricity sales revenues for Liberty Utilities (West) were U.S. $18.5 million, as compared to U.S. $13.7 million during the same period in 2012. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, 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 six months ended June 30, 2013, revenue from wastewater treatment and water distribution totalled U.S. $9.0 million and U.S. $9.3 million, respectively, as compared to U.S. $8.7 million and U.S. $9.3 million, respectively, during the same period in 2012. The increase in wastewater treatment revenue as compared to the previous period was due to increased connection counts, which increased fixed and usage revenue.

For the six months ended June 30, 2013, fuel and purchased power costs for Liberty Utilities (West)'s electric utility totalled U.S $19.5 million, as compared with U.S. $21.4 million for the same period in 2012. The overall electricity purchase expense decrease of U.S. $1.9 million was primarily the result of a U.S. $3.3 million decrease in weighted average electricity rates offset by U.S. $1.4 million increase in the volume of electricity purchased to meet customer demand, as compared to the same period in 2012.

For the six months ended June 30, 2013, operating expenses totalled U.S. $17.8 million, as compared to U.S. $17.6 million during the same period in 2012.

For the six months ended June 30, 2013, Liberty Utilities (West)'s operating profit was U.S. $19.9 million as compared to U.S. $14.9 million in the same period in 2012, an increase of U.S. $5.0 million.

Measured in Canadian dollars, Liberty Utilities (West)'s operating profit was $20.0 million as compared to $15.1 million in the same period in 2012.

2013 Second Quarter Operating Results

	Three months ended June 30	
	2013	**2012**
Average Number of Active Electric Connections		
Residential	41,390	41,350
Commercial – Small	5,430	5,510
Commercial – Large	54	54
Total Average Active Electric Connections	**46,874**	**46,914**
Average Number of Water Connections		
Wastewater connections	32,100	31,120
Water distribution connections	35,070	34,230
Total Average Water Connections	**67,170**	**65,350**
Customer Usage (GW-hrs)		
Residential	56.9	58.5
Commercial – Small	36.0	36.0
Commercial – Large	23.2	23.2
Total Customer Usage (GW-hrs)	**116.1**	**117.7**
Gallons Provided		
Wastewater treated (millions of gallons)	410	400
Water sold (millions of gallons)	1,340	1,340
Total Gallons Provided	**1,750**	**1,740**

For the three months ended June 30, 2013, Liberty Utilities (West)'s electricity usage totalled 116.1 GW-hrs, as compared to 117.7 GW-hrs for the same period in 2012, a decrease of 1.6 GW-hrs or 1%. Under the base rate revenue decoupling mechanism approved by the California Public Utilities Commission ("CPUC"), which became effective on January 1, 2013, 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, 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 Calpeco Electric System's customers according to their consumption.

During the three months ended June 30, 2013, Liberty Utilities (West) provided approximately 1,340 million gallons of water to its customers and treated approximately 410 million gallons of wastewater, as compared to 1,340 million gallons of water and 400 million gallons of wastewater during the same period in 2012.

	Three months ended June 30		Three months ended June 30	
	2013	**2012**	**2013**	**2012**
	U.S. $ (millions)	U.S. $ (millions)	**Can $ (millions)**	Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 17.1**	$ 15.7	**$ 17.5**	$ 15.9
Wastewater treatment	**4.5**	4.2	**4.6**	4.2
Water distribution	**5.5**	5.5	**5.5**	5.5
Total Revenue	**$ 27.1**	$ 25.4	**$ 27.6**	$ 25.6
Less:				
Cost of Sales – Electricity	**(8.0)**	(9.6)	**(8.2)**	(9.7)
	$ 19.1	$ 15.8	**$ 19.4**	$ 15.9
Expenses				
Operating expenses	**(8.7)**	(8.0)	**(9.1)**	(8.3)
Other income	**0.3**	0.1	**0.2**	0.1
Divisional operating profit	**$ 10.7**	$ 7.9	**$ 10.5**	$ 7.7

For the three months ended June 30, 2013, Liberty Utilities (West)'s revenue totalled U.S. $27.1 million as compared to U.S. $25.4 million during the same period in 2012, an increase of U.S. $1.7 million or 7%.

For the three months ended June 30, 2013, Liberty Utilities (West)'s revenue from utility electricity sales totalled U.S. $17.1 million as compared to U.S. $15.7 million during the same period in 2012, an increase of U.S. $1.4 million or 9%. This increase in revenues was primarily due to an increase in base revenue requirements approved in the most recent rate case that became effective January 1, 2013. The purchase of electricity by Liberty Utilities (West) is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, Liberty Utilities (West) compares 'net utility electricity sales' (utility electricity sales less fuel and purchased power costs) as a more appropriate measure of the division's results. For the three months ended June 30, 2013, net utility electricity sales revenues for Liberty Utilities (West) were U.S. $9.1 million, as compared to U.S. $6.1 million during the same period in 2012. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, 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 June 30, 2013, revenue from wastewater treatment and water distribution totalled U.S. $4.5 million and U.S. $5.5 million, respectively, as compared to U.S. $4.2 million and U.S. $5.5 million, respectively, during the same period in 2012. The increase in wastewater revenue was primarily due to an increase in average connection counts, as compared to the same period in 2012.

For the three months ended June 30, 2013, fuel and purchased power costs for Liberty Utilities (West)'s electric utility totalled U.S $8.0 million, as compared with U.S. $9.6 million for the same period in 2012. The overall electricity purchase expense decrease of U.S. $1.6 million was primarily the result of a U.S. $1.3 million decrease in weighted average electricity rates and a U.S. $0.3 million decrease in the volume of electricity purchased to meet customer demand, as compared to the same period in 2012.

For the three months ended June 30, 2013, operating expenses totalled U.S. $8.7 million, as compared to U.S. $8.0 million during the same period in 2012. The increase in operating expenses was primarily due to increased general and administrative expenses as compared to the same period in 2012.

For the three months ended June 30, 2013, Liberty Utilities (West)'s operating profit was U.S. $10.7 million as compared to U.S. $7.9 million in the same period in 2012, an increase of U.S. $2.8 million or 35%.

Measured in Canadian dollars, Liberty Utilities (West)'s operating profit was $10.5 million as compared to $7.7 million in the same period in 2012.

Liberty Utilities: Central Region

	Six months ended June 30	
	2013	**2012**
Average Number of Active Natural Gas Connections		
Residential	72,370	-
Commercial	9,280	-
Industrial	60	-
Total Average Active Natural Gas Connections	**81,710**	**-**
Average Number of Water Connections		
Wastewater connections	6,020	5,930
Water distribution connections	23,320	5,390
Total Average Water Connections	**29,340**	**11,320**
Customer Usage (MMBTU)		
Residential	3,653,380	-
Commercial	1,925,100	-
Industrial	165,300	-
Total Customer Usage (MMBTU)[1]	**5,743,780**	**-**
Gallons Provided		
Wastewater treated (millions of gallons)	190	170
Water sold (millions of gallons)	1,320	140
Total Gallons Provided	**1,510**	**310**

[1] Natural gas assets were acquired on August 1, 2012.
[2] Water distribution utility was acquired on February 1, 2013

Liberty Utilities (Central) acquired its natural gas distribution and a water distribution utility system on August 1, 2012 and February 1, 2013, respectively, and accordingly, there are no results for these utilities for the corresponding period in 2012.

For the six months ended June 30, 2013, Liberty Utilities (Central) natural gas distribution sales totalled 5,743,780 MMBTU.

During the six months ended June 30, 2013, Liberty Utilities (Central) provided approximately 1,320 million gallons of water to its customers, and treated approximately 190 million gallons of wastewater, as compared to 140 million gallons of water and 170 million gallons of wastewater during the same period in 2012.

As a result of the acquisition of the Pine Bluff Water System on February 1, 2013 the number of water connections in the region increased by 17,800. The amount of water sold also correspondingly increased by 1,130 million gallons.

		Six months ended June 30			Six months ended June 30		
		2013		2012		**2013**		2012
		U.S. $ (millions)		U.S. $ (millions)		**Can $ (millions)**		Can $ (millions)
Natural Gas Assets for regulatory purposes		**139.9**		-				
Water Assets for regulatory purposes		**52.5**		22.9				
Revenue								
Utility natural gas sales and distribution [1]	**$**	**44.6**	$	-	**$**	**45.2**	$	-
Wastewater treatment		**2.7**		2.8		**2.8**		2.8
Water distribution		**5.4**		1.7		**5.5**		1.7
		52.7		4.5		**53.5**		4.5
Less:								
Cost of Sales – Natural Gas[1]		**(27.7)**		-		**(27.9)**		-
	$	**25.0**	$	4.5	**$**	**25.6**	$	4.5
Expenses								
Operating expenses		**(12.5)**		(2.5)		**(12.7)**		(2.6)
Other income		**0.2**		-		**0.2**		-
Divisional operating profit	**$**	**12.7**		2.0		**13.1**		1.9

[1] Natural gas assets were acquired on August 1, 2012.

2013 Six Months Operating Results

Liberty Utilities (Central) has investments in natural gas distribution assets for regulatory purposes of U.S. $139.9 million and water distribution assets for regulatory purposes of U.S. $52.5 million as at June 30, 2013, as compared to U.S. $nil and U.S. $22.9 million, respectively as at June 30, 2012. The increase in water assets for regulatory purposes is primarily a result of the Pine Bluff Water System acquisition.

For the six months ended June 30, 2013, Liberty Utilities (Central)'s revenue totalled U.S. $52.7 million as compared to U.S. $4.5 million during the same period in 2012, an increase of U.S. $48.2 million. The increase in revenue is primarily attributed to the addition of the natural gas distribution assets acquired on August 1, 2012 and the Pine Bluff Water System acquired on February 1, 2013.

For the six months ended June 30, 2013, Liberty Utilities (Central)'s revenue from natural gas sales and distribution totalled U.S. $44.6 million. The purchase of natural gas by Liberty Utilities (Central) 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 natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. For the six months ended June 30, 2013, net utility natural gas sales and distribution revenue for Liberty Utilities (Central) totalled U.S. $16.9 million.

For the six months ended June 30, 2013, revenue from wastewater treatment and water distribution totalled U.S. $8.1 million, as compared to U.S. $4.5 million during the same period in 2012. The increase in wastewater treatment and water distribution revenue is primarily attributed to the addition of the Pine Bluff Water System.

For the six months ended June 30, 2013, operating expenses, excluding natural gas purchases, totalled U.S. $12.5 million, as compared to U.S. $2.5 million during the same period in 2012. The increase in operating expenses can be primarily attributed to the addition of the natural gas distribution assets on August 1, 2012 and the Pine Bluff Water System acquired on February 1, 2013.

For the six months ended June 30, 2013, Liberty Utilities (Central)'s operating profit was U.S. $12.7 million as compared to U.S. $2.0 million in the same period in 2012, an increase of U.S. $10.7 million primarily attributed to the aforementioned acquisitions.

Measured in Canadian dollars, Liberty Utilities (Central)'s operating profit was $13.1 million as compared to $1.9 million in the same period in 2012

2013 Second Quarter Operating Results

	Three months ended June 30	
	2013	**2012**
Average Number of Active Natural Gas Connections		
Residential	71,860	-
Commercial	9,220	-
Industrial	60	-
Total Average Active Natural Gas Connections	**81,140**	**-**
Average Number of Water Connections		
Wastewater connections	6,040	5,940
Water distribution connections	23,320	5,400
Total Average Water Connections	**29,360**	**11,340**
Customer Usage (MMBTU)		
Residential	968,980	-
Commercial	521,200	-
Industrial	59,200	-
Total Customer Usage (MMBTU)[1]	**1,549,380**	**-**
Gallons Provided		
Wastewater treated (millions of gallons)	100	90
Water sold (millions of gallons)	800	90
Total Gallons Provided	**900**	**180**

[1] Natural gas assets were acquired on August 1, 2012.

Liberty Utilities (Central) is comprised of Liberty Utilities' operations in Texas, Missouri, Illinois, Iowa, and Arkansas. Liberty Utilities (Central) acquired its natural gas distribution utilities and water distribution utility on August 1, 2012 and February 1, 2013, respectively, and accordingly, there are no results for these utilities for the corresponding period in 2012.

For the three months ended June 30, 2013, Liberty Utilities (Central) natural gas distribution sales totalled 1,549,380 MMBTU.

During the three months ended June 30, 2013, Liberty Utilities (Central) provided approximately 800 million gallons of water to its customers, and treated approximately 100 million gallons of wastewater, as compared to 90 million gallons of water and 90 million gallons of wastewater during the same period in 2012.

As a result of the acquisition of the Pine Bluff Water System on February 1, 2013 the number of water connections in the region increased by 17,800. The amount of water sold also correspondingly increased by 685 million gallons in the quarter.

		Three months ended June 30				Three months ended June 30		
		2013		**2012**		**2013**		**2012**
		U.S. $ (millions)		U.S. $ (millions)		**Can $ (millions)**		Can $ (millions)
Revenue								
Utility natural gas sales and distribution [1]	**$**	**13.7**	$	-	**$**	**14.0**	$	-
Wastewater treatment		**1.3**		1.4		**1.4**		1.4
Water distribution		**3.2**		1.0		**3.3**		0.9
		18.2		2.4		**18.7**		2.3
Less:								
Cost of Sales – Natural Gas[1]		**(6.9)**		-		**(7.0)**		-
	$	**11.3**	$	2.4	**$**	**11.6**	$	2.3
Expenses								
Operating expenses		**(6.0)**		(1.4)		**(6.1)**		(1.4)
Other income		**0.1**		-		**0.1**		-
Divisional operating profit	**$**	**5.4**	$	1.0	**$**	**5.6**	$	0.9

[1] Natural gas assets were acquired on August 1, 2012.
[2] Pine Bluff Water System acquired on February 1, 2013.

For the three months ended June 30, 2013, Liberty Utilities (Central)'s revenue totalled U.S. $18.2 million as compared to U.S. $2.4 million during the same period in 2012, an increase of U.S. $15.8 million. The increase in revenue can be primarily attributed to the addition of the natural gas distribution assets acquired on August 1, 2012 and the Pine Bluff Water System acquired on February 1, 2013.

For the three months ended June 30, 2013, Liberty Utilities (Central)'s revenue from natural gas sales and distribution totalled U.S. $13.7 million. The purchase of natural gas by Liberty Utilities (Central) 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 natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. For the three months ended June 30, 2013, net utility natural gas sales and distribution revenue for Liberty Utilities (Central) totalled U.S. $6.8 million.

For the three months ended June 30, 2013, revenue from wastewater treatment and water distribution totalled U.S. $4.5 million, as compared to U.S. $2.4 million during the same period in 2012. The increase in wastewater treatment and water distribution revenue can be primarily attributed to the addition of the Pine Bluff Water System.

For the three months ended June 30, 2013, operating expenses, excluding natural gas purchases, totalled U.S. $6.0 million, as compared to U.S. $1.4 million during the same period in 2012. The increase in operating expenses is primarily attributed to the addition of the natural gas distribution assets on August 1, 2012 and the Pine Bluff Water System acquired on February 1, 2013.

For the three months ended June 30, 2013, Liberty Utilities (Central)'s operating profit was U.S. $5.4 million as compared to U.S. $1.0 million in the same period in 2012, an increase of U.S. $4.4 million primarily attributed to the aforementioned acquisitions.

Measured in Canadian dollars, Liberty Utilities (Central)'s operating profit was $5.6 million as compared to $0.9 million in the same period in 2012.

In the second quarter of 2012 Interim MD&A, guidance was provided on the Liberty Utilities (Central)'s expected operating results for each quarter to the end of June 30, 2013. For the three months ended June 30, 2013, Midwest Gas System' EBITDA of U.S. $2.9 million exceeded guidance EBITDA of U.S. $2.3 million. The increased EBITDA was primarily due to operating expense savings as compared to guidance.

Liberty Utilities: East Region

	Six months ended June 30[1] 2013	2012
Average Number of Active Natural Gas Connections		
Residential	129,260	-
Commercial and Industrial	13,680	-
Total Average Active Natural Gas Connections	**142,940**	**-**
Average Number of Active Electric Connections		
Residential	35,730	-
Commercial and Industrial	7,710	-
Total Average Active Electric Connections	**43,440**	**-**
Customer Usage (GW-hrs)		
Residential	141.2	-
Commercial and Industrial	309.6	-
Total Customer Usage (GW-hrs)	**450.8**	**-**
Customer Usage (MMBTU)		
Residential	4,575,160	-
Commercial and Industrial	2,705,470	-
Total Customer Usage (MMBTU)	**7,280,630**	**-**

[1] Granite State Electric System and EnergyNorth Gas System were acquired on July 3, 2012.
[2] Columbus/Gainesville Gas System was acquired on April 1, 2013.

Liberty Utilities (East) is comprised of Liberty Utilities' operations in New Hampshire and Georgia. Liberty Utilities (East) acquired its natural gas and electric distribution systems in New Hampshire on July 3, 2012 and natural gas distribution system in Georgia on April 1, 2013; accordingly, there are no results for the corresponding period in 2012.

For the six months ended June 30, 2013, Liberty Utilities (East)'s electricity usage totalled 450.8 GW-hrs and natural gas usage totalled 7,280,630 MMBTU. The newly acquired Columbus/Gainesville Gas System usage totalled 1,184,892 MMBTU.

	Six months ended June 30 2013	2012	Six months ended June 30 2013	2012
	U.S. $ (millions)	U.S. $ (millions)	**Can $ (millions)**	Can $ (millions)
Electricity Assets for regulatory purposes	**93.7**	-		
Natural Gas for regulatory purposes	**415.0**	-		
Revenue				
Utility electricity sales and distribution[1]	**$ 40.0**	$ -	**$ 40.6**	$ -
Utility natural gas sales and distribution[1,3]	**92.3**	-	**93.5**	-
	132.3	-	**134.1**	-
Less:				
Cost of Sales – Electricity	**(26.8)**	-	**(27.2)**	-
Cost of Sales – Natural Gas[2]	**(55.3)**	-	**(56.1)**	-
	$ 50.2	$ -	**$ 50.8**	$ -
Expenses				
Operating expenses	**(29.3)**	-	**(29.7)**	-
Other Income	**1.3**		**1.3**	
Division operating profit[1]	**$ 22.2**	**$ -**	**$ 22.4**	**$ -**

[1] Granite State Electric System and EnergyNorth Gas System were acquired on July 3, 2012.
[2] Natural Gas costs includes U.S. $11.4 million regulatory authorized deferral related to an under recovery of actual gas costs.
[3] Columbus/Gainesville Gas System was acquired on April 1, 2013.

2013 Six Months Operating Results

Liberty Utilities (East) has investments in electricity assets for regulatory purposes of U.S. $93.7 million, and natural gas assets for regulatory purposes of U.S. $415.0 million as at June 30, 2013. The increase in gas assets for regulatory purposes from March 31, 2013 is primarily a result of the Columbus/Gainesville Gas System acquisition.

For the six months ended June 30, 2013, Liberty Utilities (East)'s revenue totalled U.S. $132.3 million.

For the six months ended June 30, 2013, Liberty Utilities (East)'s revenue from utility electricity sales totalled U.S. $40.0 million. The cost of electricity is passed through to Liberty Utilities (East)'s customers. As a result, the division compares 'net utility electricity sales' (revenue from electricity sales less fuel and purchased power costs) as a more appropriate measure of the division's results. For the six months ended June 30, 2013, net electricity utility sales for Liberty Utilities (East) totalled U.S. $13.2 million.

For the six months ended June 30, 2013, Liberty Utilities (East)'s revenue from natural gas sales and distribution totalled U.S. $92.3 million, of which EnergyNorth contributed $79.8 million, while the newly acquired Columbus/Gainesville Gas System contributed $12.5 million. The cost of natural gas by Liberty Utilities (East) is passed through to Liberty Utilities (East)'s customers. As a result, the division compares 'net utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. For the six months ended June 30, 2013, net utility natural gas sales and distribution revenue for Liberty Utilities (East) totalled U.S. $37.0 million.

For the six months ended June 30, 2013, electricity purchases for Liberty Utilities (East) totalled U.S. $26.8 million, and natural gas purchases totalled U.S. $55.3 million.

For the six months ended June 30, 2013, operating expenses, excluding electricity and natural gas purchases, totalled U.S. $29.3 million.

For the six months ended June 30, 2013, other income for Liberty Utilities (East) totaled U.S. $1.3 million, and primarily consists of an equity allowance for funds utilized during construction and rental income.

For the six months ended June 30, 2013, Liberty Utilities (East)'s operating profit totalled U.S. $22.2 million.

Measured in Canadian dollars, Liberty Utilities (East)'s operating profit was $22.4 million.

2013 Second Quarter Operating Results

	Three months ended June 30[1]	
	2013	**2012**
Average Number of Active Natural Gas Connections		
Residential	129,510	-
Commercial and Industrial	13,620	-
Total Average Active Natural Gas Connections	**143,130**	**-**
Average Number of Active Electric Connections		
Residential	35,780	-
Commercial and Industrial	7,840	-
Total Average Active Electric Connections	**43,620**	**-**
Customer Usage (GW-hrs)		
Residential	63.1	-
Commercial and Industrial	153.8	-
Total Customer Usage (GW-hrs)	**216.9**	**-**
Customer Usage (MMBTU)		
Residential	1,713,220	-
Commercial and Industrial	1,457,750	-
Total Customer Usage (MMBTU)	**3,170,970**	**-**

[1] Granite State Electric System and Energy North Gas System were acquired on July 3, 2012; Columbus/Gainesville Gas System was acquired on April 1, 2013.

For the three months ended June 30, 2013, Liberty Utilities (East)'s electricity usage totalled 216.9 GW-hrs and natural gas usage totalled 3,170,970 MMBTU. The newly acquired Columbus/Gainesville Gas System usage totalled 1,184,892 MMBTU.

	Three months ended June 30		Three months ended June 30	
	2013	**2012**	**2013**	**2012**
	U.S. $ (millions)	U.S. $ (millions)	**Can $ (millions)**	Can $ (millions)
Revenue				
Utility electricity sales and distribution[1]	**$ 18.4**	$ -	**$ 18.8**	$ -
Utility natural gas sales and distribution[1,2]	**33.7**	-	**34.5**	-
	52.1	-	**53.3**	-
Less:				
Cost of Sales – Electricity	**(12.4)**	-	**(12.7)**	-
Cost of Sales – Natural Gas[3]	**(17.5)**	-	**(17.9)**	-
	$ 22.2	$ -	**$ 22.7**	$ -
Expenses				
Operating expenses	**(16.0)**	-	**(16.3)**	-
Other Income	**1.0**		**1.0**	
Division operating profit[1]	**$ 7.2**	**$ -**	**$ 7.4**	**$ -**

[1] Granite State Electric System and EnergyNorth Gas System were acquired on July 3, 2012.
[2] Columbus/Gainesville Gas System was acquired on April 1, 2013.
[3] Natural Gas costs includes U.S. $1.0 million regulatory authorized deferral related to an under recovery of actual gas costs.

For the three months ended June 30, 2013, Liberty Utilities (East)'s revenue totalled U.S. $52.1 million.

For the three months ended June 30, 2013, Liberty Utilities (East)'s revenue from utility electricity sales totalled U.S. $18.4 million. The cost of electricity is passed through to Liberty Utilities (East)'s customers. As a result, the division compares 'net utility electricity sales' (revenue from electricity sales less fuel and purchased power costs) as a more appropriate measure of the division's results. For the three months ended June 30, 2013, net electricity utility sales for Liberty Utilities (East) totalled U.S. $6.0 million.

For the three months ended June 30, 2013, Liberty Utilities (East)'s revenue from natural gas sales and distribution totalled U.S. $33.7 million, of which EnergyNorth contributed $21.3 million, while the newly acquired Columbus/Gainesville Gas System contributed $12.4 million. The cost of natural gas by Liberty Utilities (East) is passed through to Liberty Utilities (East)'s customers. As a result, the division compares 'net utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. For the quarter ended June 30, 2013, net utility natural gas sales and distribution revenue for Liberty Utilities (East) totalled U.S. $16.2 million.

For the three months ended June 30, 2013, electricity purchases for Liberty Utilities (East) totalled U.S. $12.4 million, and natural gas purchases totalled U.S. $17.5 million.

For the three months ended June 30, 2013, operating expenses, excluding electricity and natural gas purchases, totalled U.S. $16.0 million.

For the three months ended June 30, 2013, other income for Liberty Utilities (East) totaled U.S. $1.0 million, and primarily consists of an equity allowance for funds utilized during construction and rental income.

For the three months ended June 30, 2013, Liberty Utilities (East)'s operating profit totalled U.S. $7.2 million.

Measured in Canadian dollars, Liberty Utilities (East)'s operating profit was $7.4 million.

In the second quarter 2012 Interim MD&A, guidance was provided on Granite State Electric System and EnergyNorth Gas System's expected operating results for each quarter ending June 30, 2013. For the three months ended June 30, 2013, Granite State Electric System's EBITDA of U.S. $1.3 million exceeded guidance EBITDA of U.S. $1.0 million, primarily due to lower than anticipated transition costs as compared to guidance. For the three months ended June 30, 2013, EnergyNorth Gas System's EBITDA of U.S. $2.2 million was lower than guidance EBITDA of U.S. $3.9 million. The decreased EBITDA for EnergyNorth Gas System can be primarily attributed to lower than expected volumes as compared to guidance, partially offset by lower than anticipated transition costs as compared to guidance.

Regulatory Proceedings

Utility	State	Regulatory Proceeding Type	Rate Request ($000's)	Current Status
Rio Rico Utilities Inc. ("Rio Rico Water System")	Arizona	Rate Case	$750	Order issued authorizing $420k annual increase
Litchfield Park Service Company ("LPSCo Water System")	Arizona	Rate Case	$3,000	Order expected first half of 2014
Granite State Electric Co. ("Granite State Electric System")	New Hampshire	Rate Case	$13,169 + $1,200 step adjustment in 2014	Temporary Rates in effect; Hearing set for January 2014
Liberty Energy (Midstates) Corp. ("Missouri Gas System")	Missouri	Accelerated Infrastructure Recovery	$540k	Order expected Q4 2013

On May 31, 2012, Liberty Utilities (West) filed a general rate case with the Arizona Corporation Commission ("ACC") related to the Rio Rico Water System. The filing sought, among other things, an increase in EBITDA by U.S. $0.8 million over 2011 results if approved as filed. On July 17, 2013, an order was received from the ACC which corresponds to an increase in EBITDA of approximately $0.4 million per year. Through the course of this rate application, Liberty Utilities also participated in a separate proceeding with other industry participants to develop a regulatory mechanism to track incremental capital expenditures in between rate cases; thus reducing regulatory lag. Liberty Utilities will be able to seek the inclusion of this mechanism in its tariffs in future rate cases, including the LPSCO Water System rate case currently before the ACC.

On February 28, 2013, Liberty Utilities (West) filed a general rate case with the Arizona Corporation Commission related to the LPSCo Water System seeking, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application seeks recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application seeks an accelerated infrastructure recovery surcharge, a purchased power pass-through mechanism to recover power price increases between test years, a property tax accounting deferral to defer increases in property taxes between test years and a policy statement on rate design to begin the gradual shift of moving more revenue recovery to fixed charges versus commodity charges. New rates are expected to be implemented in the first half of 2014.

On March 29, 2013, Liberty Utilities (East)'s electric utility filed a rate case for the Granite State Electric System with the NHPUC seeking an increase in EBITDA of U.S. $13.2 million, and an additional U.S. $1.2 million increase in 2014 subject to the completion of certain capital projects. The filing is based on a 2012 test year, with revenues and expenses adjusted to reflect known and measurable changes. Among other things, Granite State Electric System requested and received approval to continue the current cost-recovery tracking mechanism related to the Reliability Enhancement and Vegetation Management Plan and was granted an annual rate increase of $0.4 million starting July 1, 2013. Granite State Electric System also requested a modification to allow for recovery of pre-staging personnel and equipment for qualifying storms. On June 27, 2013, the NHPUC approved a settlement agreement authorizing a temporary annual rate increase of $6.5 million effective July 1, 2013, and provides recognition for Liberty to request an increase to its storm recovery adjustment factor ("SRAF"). A separate petition was filed on July 12, 2013, proposing a factor which if approved corresponds to an annual increase in storm fund recovery of approximately $1.6 million for effect with rates on November 1, 2013. The case is expected to be concluded in mid-2014.

On May 15, 2013, Liberty Utilities (East) filed its required fiscal year 2013 (April 1, 2012 – March 31, 2013) cast iron/bare steel (CIBS) replacement program results for Energy North Gas System with the NHPUC. As part of this filing, Liberty requested an annual increase in base distribution rates of $0.2 million effective July 1, 2013. On June 26, 2013 the NHPUC granted Liberty's request.

On July 2, 2013, Liberty Utilities (Central) filed an application on behalf of the Missouri Gas System with the Missouri Public Service Commission ("MPSC") seeking accelerated recovery for infrastructure deployed under the utility's infrastructure system replacement surcharge ("ISRS"). The filing seeks an increase in EBITDA of $0.5 million if approved as filed and is expected to be approved in Q4 2013.

Outlook – Liberty Utilities

Liberty Utilities (West) expects continuing modest customer growth throughout its respective service territories in 2013.

Primarily as a result of the rate case at the Calpeco Electric System approved in late 2012, additional EBITDA of U.S. $7.1 million is expected in 2013 compared to the results achieved in the previous year.

APUC: Corporate and Other Expenses

	Three months ended June 30		Six months ended June 30	
	2013	**2012**	**2013**	**2012**
Corporate and other expenses:	**(millions)**	(millions)	**(millions)**	(millions)
Administrative expenses	**$ 7.3**	$ 5.5	**$ 12.2**	$ 9.9
(Gain)/Loss on foreign exchange	**(0.8)**	(0.9)	**(1.3)**	(0.4)
Interest expense	**12.9**	6.2	**25.1**	14.9
Interest, dividend and other Income	**(0.8)**	(0.6)	**(1.3)**	(1.3)
Acquisition-related costs	**0.5**	2.1	**1.0**	4.4
(Gain)/Loss on derivative financial instruments	**(0.5)**	0.7	**(1.9)**	0.6
Income tax expense/(recovery)	**0.9**	(1.0)	**7.2**	(3.3)

2013 Six Months Corporate and Other Expenses

During the six months ended June 30, 2013, administrative expenses totalled $12.2 million, as compared to $9.9 million in the same period in 2012. The expense increase in the period primarily results from additional personnel, increased wages, additional costs required to administer APUC's operations, and other costs as compared to the same period in 2012 as a result of the continued growth in the company.

During the six months ended June 30, 2013, interest expense totalled $25.1 million as compared to $14.9 million in the same period in 2012. The increased interest expense is a result of new indebtedness incurred during the second half of 2012 used to partially finance the new acquisitions. These amounts were partially offset by reduced interest expense related to convertible debentures due to the conversion of the Series 3 Debentures in the fourth quarter of 2012, and $1.7 million in 2012 related to the Quebec water lease litigation.

During the six months ended June 30, 2013, interest, dividend and other income totalled $1.3 million, which is consistent with the same period in 2012. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

During the six months ended June 30, 2013, acquisition related costs totalled $1.0 million as compared to $4.4 million in the same period in 2012. Acquisition related costs will vary from quarter to quarter depending on the level of activity and complexity associated with various acquisitions.

An income tax expense of $7.2 million was recorded in the six months ended June 30, 2013, as compared to a recovery of $3.3 million during the same period in 2012. The income tax expenses for the six months ended June 30, 2013 is primarily due to higher earnings in the U.S. resulting from the various U.S. acquisitions completed in 2012, deferred taxes on HLBV income, the recognition of deferred credits from the utilization of deferred income tax assets recognized at the time of the Unit Exchange Offer, non-taxable inter-corporate dividends, and other items permanently excluded from Canadian taxable income.

2013 Second Quarter Corporate and Other Expenses

During the three months ended June 30, 2013, administrative expenses totalled $7.3 million, as compared to $5.5 million in the same period in 2012. The expense increase in the quarter primarily results from additional personnel, increased wages, additional costs required to administer APUC's operations, and other costs as compared to the same period in 2012 as a result of the continued growth in the company.

During the three months ended June 30, 2013, interest expense totalled $12.9 million as compared to $6.2 million in the same period in 2012. The increased interest expense is a result of new indebtedness incurred or inherited during the second half of 2012, and the first two months of 2013 used to partially finance the new acquisitions. These amounts were partially offset by reduced interest expense related to convertible debentures due to the conversion of the Series 3 Debentures in the fourth quarter of 2012.

During the three months ended June 30, 2013, interest, dividend and other income totalled $0.8 million as compared to $0.6 million in the same period in 2012. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

During the three months ended June 30, 2013, acquisition related costs totalled $0.5 million as compared to $2.1 million in the same period in 2012. Acquisition related costs will vary from quarter to quarter depending on the level of activity and complexity associated with various acquisitions.

An income tax expense of $0.9 million was recorded in the three months ended June 30, 2013, as compared to a recovery of $1.0 million during the same period in 2012. The income tax expenses for the three months ended June 30, 2013 is primarily due to higher earnings in the U.S. resulting from the various U.S. acquisitions completed in 2012, deferred taxes on HLBV income, the recognition of deferred credits from the utilization of deferred income tax assets recognized at the time of the Unit Exchange Offer, non-taxable inter-corporate dividends, and other items permanently excluded from Canadian taxable income.

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

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 depreciation and amortization expense, income tax expense or recoveries, acquisition costs, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the interim unaudited 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 June 30		**Six months ended June 30**	
	2013	**2012**	**2013**	**2012**
	(millions)	(millions)	**(millions)**	(millions)
Net earnings/(loss) attributable to Shareholders	**$ (18.1)**	$ 6.1	**$ 1.1**	$ 8.3
Add (deduct):				
Net earnings/(loss) attributable to the non-controlling interest, exclusive of HLBV income	**4.1**	0.4	**7.1**	1.0
(Earnings)/loss from discontinued operations	**33.9**	(0.8)	**35.0**	(1.1)
Income tax expense/(recovery)	**0.9**	(1.0)	**7.2**	(3.3)
Interest expense	**12.9**	6.2	**25.1**	14.9
Acquisition costs	**0.5**	2.1	**1.0**	4.4
Quebec water lease litigation	**-**	-	**-**	0.5
(Gain)/Loss on derivative financial instruments	**(0.5)**	0.7	**(1.9)**	0.6
(Gain)/Loss on foreign exchange	**(0.8)**	(0.9)	**(1.3)**	(0.4)
Depreciation and amortization	**23.6**	9.4	**45.6**	18.5
Adjusted EBITDA	**$ 56.5**	$ 22.2	**$ 118.9**	$ 43.4

Hypothetical Liquidation at Book Value ("HLBV") income 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 six months ended June 30, 2013 amounted to approximately U.S. $7.5 million and U.S. $12.6 million, respectively.

For the six months ended June 30, 2013, Adjusted EBITDA totalled $118.9 million as compared to $43.4 million during the same period in 2012, an increase of $75.5 million. For the three months ended June 30, 2013, Adjusted EBITDA totalled $56.5 million as compared to $22.2 million during the same period in 2012, an increase of $34.3 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 June 30 (millions)		Six months ended June 30 (millions)	
Comparative Prior Period Adjusted EBITDA	$	22.2	$	43.4
Significant Changes:				
Liberty Utilities				
Increased demand and rate decoupling at the Calpeco Electric System		3.2		5.6
Acquisition of U.S. utilities		10.2		31.1
APCo:				
Renewable				
Increased hydrologic resource		1.3		1.8
Acquisition of U.S. Wind Facilities		17.0		33.9
Renewable Energy Credits sales		1.5		2.5
St Leon II – facility expansion		0.8		1.4
Increase due to prior year planned shutdown at Tinker facility		-		0.6
Thermal				
Windsor Locks – Reduced energy sales		1.4		0.7
Administrative expense		(1.8)		(2.3)
Increased results from the stronger U.S. dollar		0.7		1.1
Other		-		(0.9)
Current Period Adjusted EBITDA	$	56.5	$	118.9

Reconciliation of adjusted net earnings to 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 gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, litigation expenses and write down of intangibles and property, plant and equipment 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.

The following table is derived from and should be read in conjunction with the interim unaudited 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 June 30		Six months ended June 30	
	2013	**2012**	**2013**	**2012**
	(millions)	(millions)	**(millions)**	(millions)
Net earnings/(loss) attributable to Shareholders	**$ (18.1)**	$ **6.1**	**$ 1.1**	$ 8.3
Add (deduct):				
(Earnings)/loss from discontinued operations, net of tax	**33.9**	**(0.8)**	**35.0**	(1.1)
(Gain)/Loss on derivative financial instruments, net of tax	**(0.4)**	**0.4**	**(1.5)**	0.5
Quebec water lease litigation and interest, net of tax	**-**	**-**	**-**	1.6
Cross currency swap interest rate differential	**0.2**	**-**	**0.3**	-
(Gain)/Loss on foreign exchange, net of tax	**(0.5)**	**(0.5)**	**(0.8)**	(0.2)
Acquisition costs, net of tax	**0.3**	**1.3**	**0.6**	2.7
Adjusted net earnings	**$ 15.4**	$ 6.5	**$ 34.7**	$ 11.8
Adjusted net earnings per share	**$ 0.08**	$ 0.04	**$ 0.17**	$ 0.08

For the six months ended June 30, 2013, adjusted net earnings totalled $34.7 million as compared to adjusted net earnings of $11.8 million, an increase of $22.9 million as compared to the same period in 2012. The increase in adjusted net earnings for the six months ended June 30, 2013 is primarily due to higher income from operations, and interest and dividends partially offset by higher depreciation and amortization expense, higher interest expense, higher administration costs and income tax expense amounts as compared to the same period in 2012.

For the three months ended June 30, 2013, adjusted net earnings totalled $15.4 million as compared to adjusted net earnings of $6.5 million, an increase of $8.9 million as compared to the same period in 2012. The increase in adjusted net earnings for the three months ended June 30, 2013 is primarily due to higher income from operations, and interest and dividends partially offset by higher depreciation and amortization expense, higher interest expense, higher administration costs and income tax expense amounts as compared to the same period in 2012.

Reconciliation of adjusted funds from operations to cash flows from operating activities

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 and litigation expense. 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 changes in working capital balances, acquisition and litigation expense 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.

The following table is derived from and should be read in conjunction with the interim unaudited 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 June 30		Six months ended June 30	
	2013 (millions)	**2012 (millions)**	**2013 (millions)**	**2012** (millions)
Cash flows from operating activities	**$ 57.4**	$ 17.3	**$ 52.7**	$ 28.4
Add (deduct):				
Changes in non-cash operating items	**(23.8)**	1.7	**28.1**	1.4
Cash provided/(used) in discontinued operation	**3.0**	(2.6)	**2.9**	(4.6)
Cross currency swap interest rate differential	**-**	-	**0.1**	-
Acquisition costs	**0.5**	2.1	**1.0**	4.4
Adjusted funds from operations	**$ 37.1**	$ 18.5	**$ 84.8**	$ 29.6
Adjusted funds from operations per share	**$ 0.18**	$ 0.11	**$ 0.42**	$ 0.20

For the six months ended June 30, 2013, adjusted funds from operations totalled $84.8 million as compared to adjusted funds from operations of $29.6 million, an increase of $55.2 million as compared to the same period in 2012.

For the three months ended June 30, 2013, adjusted funds from operations totalled $37.1 million as compared to adjusted funds from operations of $18.5 million, an increase of $18.6 million as compared to the same period in 2012.

Summary of Property, Plant and Equipment Expenditures

	Three months ended June 30		Six months ended June 30	
	2013	**2012**	**2013**	**2012**
	(millions)	**(millions)**	**(millions)**	**(millions)**
APCo:				
Renewables	$ 7.9	$ 6.7	$ 12.0	$ 9.6
Thermal	0.1	8.0	0.3	14.2
Total APCo:	**$ 8.0**	**$ 14.7**	**$ 12.3**	**$ 23.8**
Liberty Utilities:				
West	2.2	3.2	3.7	4.6
Central	6.4	1.1	13.5	2.3
East	22.1	-	25.7	-
Total Liberty Utilities:	**30.7**	**4.3**	**42.9**	**6.9**
Corporate	0.7	-	0.7	-
Total	**$ 39.4**	**$ 19.0**	**$ 55.9**	**$ 30.7**

APUC has a total capital expenditure plan for all of 2013 of approximately $160 million of which $55.9 million has been invested in the half of the year leaving approximately $104.1 million expected to be invested in the second half of 2013. In 2013 APCo expects to invest approximately $60 million primarily relating to the development of the Cornwall solar project and Liberty Utilities expects to invest approximately $100 million 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, working capital and bank credit facilities to finance its property, plant and equipment expenditures and other commitments.

2013 Six Month Property Plant and Equipment Expenditures

During the six months ended June 30, 2013, APCo incurred capital expenditures of $12.3 million, as compared to $23.8 million during the comparable period in 2012.

During the six months ended June 30, 2013, APCo's Renewable Energy Division spent $12.0 million in capital expenditures as compared to $9.6 million in the comparable period in 2012. The capital expenditures primarily relate to major repairs and upgrades at the Long Sault and Tinker hydro facilities, as well as project costs related to the Cornwall Solar, Chaplin and St Damase developments. APCo's Thermal Energy Division net capital expenditures were $0.3 million, as compared to $14.2 million in the comparable period in 2012. The capital expenditures in the prior year were primarily related to the Windsor Locks repowering and the major maintenance at the Sanger facility.

During the six months ended June 30, 2013, Liberty Utilities invested $42.9 million in capital expenditures as compared to $6.9 million during the comparable period in 2012. Liberty Utilities (West)'s spend was primarily related to growth and upgrades at the Calpeco Electric System and the expansion of the LPSCo Water System. Liberty Utility (Central)'s $13.5 million investment in capital expenditures was primarily related to pipe expansion and replacement activities and IT system implementations, as a result of the Midwest Gas Systems acquisition. Liberty Utility (East)'s $25.7 million investment in capital expenditures was primarily related to the installation of the Michael Ave. Substation and Enfield second supply line on the Granite State Electric system and the installation of new mains and services supporting growth and system reinforcements on the EnergyNorth Gas system.

2013 Second Quarter Property Plant and Equipment Expenditures

During the three months ended June 30, 2013, APCo incurred capital expenditures of $8.0 million, as compared to $14.7 million during the comparable period in 2012.

During the three months ended June 30, 2013, APCo's Renewable Energy Division spent $7.9 million in capital expenditures as compared to $6.7 million in the comparable period in 2012. The capital expenditures primarily relate to major repairs and upgrades at the Long Sault and Tinker facilities, as well as project costs related to the Cornwall Solar, Chaplin Wind Project and St Damase Wind Project developments. APCo's Thermal Energy Division net capital expenditures were $0.1 million, as compared to $8.0 million in the comparable period in 2012. The capital expenditures in the prior year were primarily related to the Windsor Locks Facility repowering and the major maintenance at the Sanger.

During the three months ended June 30, 2013, Liberty Utilities invested $30.7 million in capital expenditures as compared to $4.3 million during the comparable period in 2012. Liberty Utilities (West)'s spend was primarily related to growth and upgrades at the Calpeco Electric System and the expansion of the LPSCo Water System. Liberty Utility (Central)'s $6.4 million investment in capital expenditures was primarily related to pipe expansion and replacement activities and IT system implementations, as a result of the Missouri Gas System, and Illinois Gas System acquisitions. Liberty Utility (East)'s $22.1 million investment in capital expenditures was primarily related to the installation of the Michael Ave. Substation and Enfield second supply line on the Granite State Electric System and the installation of new mains and services supporting growth and system reinforcements on the EnergyNorth Gas System.

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C93), APCo's Renewable Energy Division completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. Out of these, nine remedial plans 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 two facilities, remediation work is underway at one facility, monitoring activities and options analysis are being performed for two facilities, and remedial work is being planned at two facilities.

APCo currently estimates further capital expenditures of approximately $16.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

	Total	2013	2014	2015	2016
Future Estimated Bill C-93 Capital Expenditures	16,900	500	5,400	5,700	5,300

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

- APCo completed the majority of the on-site remediation work for the Mont Laurier Facility in 2012 at a capital cost of approximately $0.3 million. Phase two of the on-site remediation work is scheduled for third and fourth quarters of 2013 at an estimated cost of $0.1 million.
- APCo completed the dam safety evaluation for the Donnacona Facility and has obtained the Certificate of Authorization from the Quebec government. The remedial on-site work is anticipated to start in 2014 and be completed in 2015.

- The dam safety study and a detailed condition assessment for the St. Alban Facility have been completed. APCo anticipates engineering and regulatory review to be performed in 2014, with remedial work in 2015 to 2016.
- APCo is presently reviewing options with respect to the Belleterre Facility including the removal of several small dams that are not required for power generation. APCo anticipates completion of any required work on these dams by 2016.
- Engineering for the Riviere-du-Loup Facility dam modifications was completed in 2012. Following a geotechnical investigation the remediation work is now estimated at $1.1million. Completion of the remedial work is anticipated in 2014 and 2015.
- The dam remediation work related to the Rawdon and Chute Ford Facilities has been completed.

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 "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 June 30, 2013 under the Facilities:

	As at June 30, 2013				As at Dec 31, 2012
	APUC	**APCo**	**Liberty Utilities**	**Total**	**Total**
	(millions)	**(millions)**	**(millions)**	**(millions)**	**(millions)**
Committed Facilities	$ 30.0	$ 200.0	$ 105.2	$ **335.2**	$ 329.5
Funds drawn on Facilities	-	(69.5)	(31.6)	(101.1)	(54.5)
Letters of Credit issued	(6.0)	(42.4)	(5.5)	(53.9)	(50.7)
Funds available for draws on the Facilities	**$ 24.0**	**$ 88.1**	**$ 68.1**	**$ 180.2**	**$ 224.3**
Cash on Hand				37.4	53.1
Total liquidity and capital reserves	**$ 24.0**	**$ 88.1**	**$ 68.1**	**$ 217.6**	**$ 277.4**

As at June 30, 2013, the APUC $30.0 million senior unsecured revolving credit facility ("APUC Facility") was undrawn and had $6.0 million of outstanding letters of credit.

As at June 30, 2013, the APCo $200.0 million senior unsecured revolving credit facility (the "APCo Facility") had drawn $69.5 million and had $42.4 million in outstanding letters of credit under the APCo Facility.

As at June 30, 2013, the Liberty Utilities U.S. $100.0 million senior unsecured revolving credit facility (the "Liberty Facility") had drawn $31.6 million and had $5.5 million of outstanding letters of credit under the Liberty Facility.

Long Term Debt

On January 1, 2013, in conjunction with the acquisition of the Shady Oaks Wind Facility, APCo assumed a U.S. $150 million dollar variable rate long term credit facility. The facility is secured by the assets of the Shady Oaks Wind Facility. APCo made a principal payment of U.S. $25 million in the second quarter of 2013 and will be required to make semi-annual principal payments ranging between U.S. $3 million and U.S. $6 million thereafter. The facility matures in 2026. Funds advanced against the facility are repayable at any time without penalty.

On March 14, 2013 Liberty Utilities entered into a U.S. $100 million non-revolving term credit facility with a U.S. Bank. On April 1, 2013 Liberty used the full amount available under the facility in connection with closing of the Columbus/Gainesville Gas System. On July 31, 2013, concurrent with the closing of the U.S. $125 million private placement the facility was repaid in full.

On March 14, 2013 Liberty Utilities completed a U.S. $15 million private placement debt financing. The notes are senior unsecured notes with a 10 year bullet maturity and carry a coupon of 4.14%.

On July 31, 2013, Liberty Utilities issued U.S. $125 million of debt through a private placement. The notes are senior unsecured with an average life maturity of ten years and a weighted average coupon of 3.81%. The proceeds of the private placement financing were used to repay the U.S. $100 million term facility and reduce the drawn amount on Liberty's revolving credit facility.

Contractual Obligations

Information concerning contractual obligations as of June 30, 2013 is shown below:

		Total		Due less than 1 year		Due 1 to 3 years		Due 4 to 5 years		Due after 5 years
		(millions)		(millions)		(millions)		(millions)		(millions)
Long-term debt obligations[1]	$	1,091.6		8.2		223.2		82.5		777.7
Advances in aid of construction	$	79.6		0.6		-		-		79.0
Interest on long-term debt obligations	$	367.8		48.7		91.4		81.5		146.2
Purchase obligations	$	115.4		115.4		-		-		-
Environmental Obligations	$	62.8		1.0		33.5		17.7		10.6
Derivative financial instruments:										
Cross Currency Swap	$	6.7		-		-		-		6.7
Interest rate swap	$	3.7		1.9		1.8		-		-
Energy derivative contracts	$	10.4		1.1		0.2		-		9.1
Capital lease obligations	$	0.2		0.1		0.1		-		-
Capital projects	$	20.7		20.2		0.5				
Long term service agreements	$	636.5		25.8		49.3		57.2		504.2
Purchased power	$	122.6		58.1		64.5		-		-
Gas delivery, service and supply agreements	$	119.3		26.6		28.6		11.2		52.9
Operating leases	$	110.0		5.3		9.1		6.9		88.7
Other obligations	$	20.8		4.3		-		-		16.5
Total obligations	$	2,768.1	$	317.3	$	502.2	$	257.0	$	1,691.6

1 Long term obligations include regular payments related to long term debt and other obligations.

Equity

The shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at June 30, 2013, APUC had 204,997,926 issued and outstanding common shares.

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

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at June 30, 2013, APUC had 4,800,000 cumulative rate reset preferred shares, Series A (the "Series A Shares") issued and outstanding, yielding 4.5% per cent annually for the initial six-year period ending on December 31, 2018. The preferred shares have been assigned a rating of P-3 and Pfd-3(low) by S&P and DBRS respectively.

As at June 30, 2013, APUC had issued 100 redeemable Series C preferred shares (the "Series C Shares") that were issued in exchange for 100 Class B limited partnership units issued by the St. Leon Wind Energy LP. The Series C Shares are mandatorily redeemable in 2031.

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of shares ("Shareholders") of APUC. APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of shares ("Shareholders") of APUC. As at June 30, 2013, 48.6 million common shares representing approximately 24% of total shares outstanding had been registered with the Reinvestment Plan, and during the second quarter 499,185 common shares were issued under the Reinvestment Plan. Subsequent to the end of the quarter, on July 15, 2013, an additional 614,136 common shares were issued under the Reinvestment Plan.

Emera subscription receipts

In 2013, a total of 15.2 million common shares have been issued to Emera for proceeds of $90.4 million pursuant to subscription agreements in contemplation of certain previously announced transactions, as outlined below:

- On February 7, 2013 and February 14, 2013, respectively, in connection with the closing of the acquisition of the Minonk and Senate Wind Facilities from Gamesa USA that occurred on December 10, 2012, APUC issued 2.6 million common shares at a price of $5.74 and 5.2 million shares at a price of $5.74. The total $45 million in cash proceeds from the exercise of the subscription receipts were used to fund a portion of the cost of the acquisition;
- On February 14, 2013, in connection with the acquisition of Emera's noncontrolling interest in Calpeco, APUC issued 3.4 million common shares at a price of $4.72 for share proceeds of $16.1 million; and
- On March 26, 2013, in connection with the acquisition of the Georgia Utility, APUC issued 4.0 million shares at a price of $7.40 per share to Emera pursuant to a subscription agreement, for total cash proceeds of $29.3 million. The cash proceeds were used to partially fund the acquisition of the Georgia Utility.

As at August 12, 2013, in total, Emera owns 50.1 million APUC common shares representing approximately 24.5% of the total outstanding common shares of the Company. APUC believes issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

SHARE-BASED COMPENSATION PLANS

For the three and six months ended June 30, 2013, APUC recorded $563 and $987 (2012 - $617 and $846) 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 Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at June 30, 2013, total unrecognized compensation costs related to non-vested options and share unit awards were $3,012 and $153 respectively, which are expected to be recognized over a period of 1.82 years and 1.35 years respectively.

STOCK OPTION PLAN

APUC has a stock option plan that permits the grant of share options to key officers, directors, employees and selected service providers. Except in certain circumstances, the term of an Option shall not exceed ten (10) years from the date of the grant of the Option.

For the quarter ended June 30, 2013, no additional options were granted to senior executives or certain senior management of APUC. As at June 30, 2013, APUC had 4,567,129 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 has a Performance Share Unit as part of its long-term incentive program. Performance share units ("PSUs") are granted to certain employees annually for three-year overlapping performance cycles. The PSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these PSUs are accounted for as equity awards. For the quarter ended June 30, 2013, no additional PSUs were granted. As at June 30, 2013, 85,230 PSUs had been granted.

DIRECTORS DEFERRED SHARE UNITS

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

As at June 30, 2013, 61,842 DSUs had been granted.

EMPLOYEE SHARE PURCHASE PLAN

APUC has an employee share purchase plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. As at June 30, 2013, a total of 98,775 shares had been issued under the ESPP.

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

Certain executives of APUC are shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of the Company. A member of the Board of Directors of APUC is an executive at Emera.

Transactions with APMI and Senior Executives

- APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the three and six months ended June 30, 2013 were $84 and $168 (2012 $82 and $164).

- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. During the three and six months ended June 30, 2013, APUC incurred costs in connection with the use of the aircraft of $78 and $146 (2012 $104 and $164) and amortization expense related to the advance against expense reimbursements of $nil (2012 - $88 and $155). At June 30, 2013, the remaining amount of the advance was $nil (December 31, 2012 - $nil).

- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon LP, a subsidiary of APUC and the legal owner of the St. Leon facility. The related holders of the Class B units received cash distributions of $nil for the three and six months ended June 30, 2013 (2012 - $80 and $155). On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the Class B units (note 10).

- APUC provided supervisory management services on a cost recovery basis to a hydroelectric generating facility not owned by APUC where Senior Executives hold an equity interest

- Rattle Brook is a hydroelectric generating facility in which APUC owns a 45% interest and Senior Executives hold an equity interest in. Rattle Brook is operated on a cost recovery basis by an entity which is partially owned by Senior Executives.

- APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of

Red Lily I. In 2011, APUC acquired APMI's interest in this royalty. An amount of $600 has been accrued as an estimate of the final fee owed to APMI.

- As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee. An amount of U.S. $550 has been accrued as an estimate of the final fee owed to APMI.
- During 2007, APUC allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee of $1,800. As part of its role in the process, APUC has agreed to pay APMI a fee of $100 which has been accrued as an estimate of the final fee owed to APMI.
- As at June 30, 2013, due from related parties include $814 (December 31, 2012 - $816) owed to APUC from APMI and due to related parties include $1,839 (December 31, 2012 - $1,811) owed to APMI. These amounts arise from the transactions described above.
- Long Sault is a hydroelectric generating facility in which APUC acquired its interest by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the after tax equity cash flows commencing in 2014.
- In March 2012, APUC and APMI's Senior Executives (the "Parties") reached a term sheet agreement to resolve a number of the historic joint business associations between the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed before the end of 2013.
- Under the term sheet, it is proposed that APUC will exchange its 45% interest in the 4MW Rattle Brook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement is based on an assumed transaction date of January 1, 2012 and also settles outstanding fees owing to APMI.

Transactions with Emera

- In 2011, a subsidiary of Emera provided lead market participant services for fuel capacity and forward reserve markets to ISO NE for the Windsor Locks facility. During the three and six months ended June 30, 2013 APUC paid U.S. $nil (2012 – U.S. $69 and $160) in relation to this contract. In 2011, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.
- For the three and six months ended June 30, 2013, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $1,527 and $3,162 (2012 – U.S. $1,477 and $2,990). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S. $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.
- The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

Business Associations with APMI and Senior Executives

There have been historic business relationships between Ian Robertson and Chris Jarratt ("Senior Executives"), APMI and related affiliates (collectively the "Parties") and APUC. In 2011, the Board initiated a process to review all of the remaining business associations with the Parties in order to reduce, streamline and simplify these relationships. The Board formed a special committee and engaged independent consultants to assist with this process.

The co-owned assets and remaining business associations as at June 30, 2013 are listed below. During the quarter ended March 31, 2012, APUC and the Parties reached an agreement to resolve a number of the business associations and relationships (the "Agreement"). A more detailed description of the Agreement has been set out below in Settlement of Other Business Associations.

- *Rattle Brook hydroelectric generating facility*

  Rattle Brook is a 4 MW hydroelectric generating station owned 45% by APUC, 27.5% by Senior Executives and the remaining percentage by third parties. This relationship was addressed pursuant to the Agreement. See Settlement of Other Business Associations below for more details.

- *Brampton Cogeneration Inc.*

  BCI is an energy supply facility which sells steam produced from APCo's EFW facility. APMI has a partnership interest equal to 50% of the annual returns on the project greater than 15%. No amounts have ever been paid under this carried interest. In 2008, APMI earned a construction supervision fee of $0.1 in relation to the development of this project. See Settlement of Other Business Associations below for more details.

- *Long Sault Rapids hydroelectric generating facility*

  Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the equity cash flows commencing in 2014. See Settlement of Other Business Associations below for more details.

- *Office lease*

  APUC has leased a portion of its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The lease expires on December 31, 2015.

- *Operations services*

  APUC has historically provided supervisory management on a cost recovery basis for one small hydro facility in which Senior Executives hold an indirect equity interest. The board has agreed to extend the existing relationship pursuant to an agreement that can be terminated by either party upon 30 days written notice until December 31, 2013.

- *Sanger construction management*

  As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based fee. An amount of U.S. $0.6 million has been accrued as an estimate of the fee owed to APMI. See Settlement of Other Business Associations below for more details.

- *Clean Power Income Fund*

  During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund ("Clean Power") to expire and earned a termination fee of $1.8 million. As part of its role in the process, APUC has agreed to pay APMI a fee of $0.1 million. Since December 31, 2011 this amount is accrued and included in due to related parties on the consolidated balance sheet. See Settlement of Other Business Associations below for more details.

- *Red Lily I*

  APMI was an early developer of the 26 MW Red Lily I wind power generation facility. As such it is entitled to a royalty fee based on a percentage of operating revenue and a development fee from Red Lily I. See Settlement of Other Business Associations below for more details.

- *Trafalgar*

  APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar was previously awarded a U.S. $10.0 million claim in respect of a lawsuit related to faulty engineering in the design of these facilities, and these funds are held in the bankruptcy estate. As previously disclosed, Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. APMI funded the initial $2 million in legal fees. An agreement was reached in 2004 between APMI and APUC whereby APUC would reimburse APMI 50% of the legal costs to date in an amount of approximately $1 million, and going forward APUC would fund the legal fees, third party costs and other liabilities with the proceeds from the lawsuits being shared after reimbursement of legal fees, third party costs and other liabilities. The Board has determined that any proceeds from the lawsuit will be shared between APMI and APUC proportionally to the quantum of such costs funded by each party.

Settlement of Other Business Associations

During the quarter ended March 31, 2012, APUC and APMI's Senior Executives (the "Parties") reached agreement ("Agreement") to resolve a number of the historic joint business associations between APUC and the Parties. The Agreement is based on an effective date of January 1, 2012 and the transaction is subject to finalization of definitive agreements which are expected to be completed before the end of 2013.

Under the Agreement, APUC will exchange its 45% interest in the 4MW Rattle Brook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual equity interest in the Long Sault Rapids hydroelectric facility and the partnership interest in the Brampton cogeneration plant. The agreement also terminates all outstanding fees potentially owing to APMI in respect of historic transactions.

The special committee of the Board retained the services of an independent advisor to review the historic financial performance of the Rattle Brook and Long Sault Rapids facilities, provide a valuation of these assets and to provide advice to APUC in respect thereof.

TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that both APCo and Liberty Utilities maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies to manage its risk exposures.

There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, interest rate, liquidity and commodity price risk considerations, and credit risk associated with a reliance on key customers. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the 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.

On May 15, 2012, APCo entered into a financial hedge, which expires December 31, 2016 with respect to its Dickson Dam hydroelectric facility located in the Western region. The financial hedge is structured to hedge 75% of APCo's production volume against exposure to the Alberta Power Pool's current spot market rates. For the unhedged portion of production, each $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of $0.2 million on an annualized basis.

The July 1, 2012 acquisition of Sandy Ridge Wind Facility included a financial hedge which commenced on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's production volume against exposure to PJM Western Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $0.3 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 Senate Wind Facility's production volume against exposure to ERCOT North Zone current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $1.1 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 production volume against exposure to PJM Northern Illinois Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in market prices would result in a change in revenue of about $1.1 million for the year.

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, each $10 per MW-hr change in market prices would result in a change in revenue of about $1.1 million for the year.

Interest rate risk

APUC's operating credit facility is subject to a variable interest rate. The APUC Facility has no amounts outstanding as at June 30, 2013. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.

The APCo Facility had $69.5 million outstanding as at June 30, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $7.0 million annually.

The Liberty Facility had $31.6 million outstanding as at June 30, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $3.2 million annually.

The Shady Oaks Senior Debt Facility had $131.5 million outstanding as at June 30, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.3 million annually.

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 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 June 30, 2013, APUC and its subsidiaries had a combined $180.2 million of committed and available credit facilities remaining and $37.4 million of cash resulting in $217.6 million of total liquidity and capital reserves.

APUC currently pays a dividend of $0.34 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 long term portion of debt totals approximately $1,091.5 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facilities and project debt with borrowings having less favorable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted.

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

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, 2012 and 2011 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 detailed 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.

A subsidiary of APUC ("Algonquin") owns debt on seven hydroelectric facilities owned by Trafalgar. In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar, Algonquin and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings.

With respect to the civil proceedings, the United States Second Circuit Court of Appeals dismissed all the claims against Algonquin in the civil proceedings and remanded one issue to the District Court. On April 3, 2012, the District Court granted Algonquin summary judgment on its counter-claims against Trafalgar. The District Court found that Trafalgar was in default of the indenture and the loan agreements and that Algonquin was entitled to proceed to enforce its rights against its collateral. Trafalgar filed a notice of appeal of the Memorandum-Decision and Order. The appeal was argued on March 21, 2013. On March 25, 2013, the United States Second Circuit Court of Appeals affirmed the decision of the District Court giving Algonquin judgment on its claims. Trafalgar has asked the United States Second Circuit Court of Appeals for reconsideration of its decision or to certify a legal question to the Connecticut Supreme Court. On May 21, 2013, the United States Second Circuit Court of Appeals denied TPI's petition and the matter was sent back to the District Court for further proceedings with respect to the enforcement of Algonquin's remedies under the loan documents, including the calculation of the debt and the disposition of collateral.

With respect to the bankruptcy proceedings, on January 30, 2013, the United States Second Circuit Court of Appeals held that Algonquin did have a security interest in Trafalgar's engineering malpractice claim and its proceeds. On February 20, 2013, Trafalgar filed a petition for a rehearing with the United States Second Circuit Court of Appeals which petition was denied on June 17, 2013. Algonquin filed and served a motion seeking an order terminating the automatic stay and directing the distribution of the funds held in the escrow account to Algonquin. Algonquin's motion for relief from the automatic stay has been adjourned to August 15, 2013 for submission of written arguments regarding the effect of the various decisions on the defenses TPI raised to the motion for relief from stay and for future oral argument.

On October 21, 2011 the Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5.4 million (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. The potential unrecoverable loss, if any, for the related prior periods could be up to $5.8 million. The parties are attempting to resolve this matter through good faith negotiations.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the eight quarters ended June 30, 2013:

Millions of dollars (except per share amounts)	3rd Quarter 2012	4th Quarter 2012	1st Quarter 2013	2nd Quarter 2013
Revenue	$ 93.0	$ 138.9	$ 193.1	$ 148.8
Adjusted EBITDA	22.1	32.3	61.8	56.5
Net earnings / (loss) attributable to shareholders from continuing operations	(0.9)	6.8	20.4	15.8
Net earnings / (loss) attributable to shareholders	(0.2)	6.4	19.2	(18.1)
Net earnings / (loss) per share from continuing operations	(0.01)	0.04	0.10	0.08
Net earnings / (loss) per share	0.00	0.04	0.10	(0.09)
Adjusted net earnings	2.9	5.6	19.4	15.4
Adjust net earnings per share	0.02	0.03	0.10	0.08
Total Assets	1,967.1	2,778.2	2,990.7	3,201.8
Long term debt*	705.1	771.8	917.5	1,091.5
Dividend declared per common share	0.08	0.08	0.08	0.09

	3rd Quarter 2011	4th Quarter 2011	1st Quarter 2012	2nd Quarter 2012
Revenue	$ 59.4	$ 64.8	$ 58.1	$ 58.7
Adjusted EBITDA	23.3	22.1	21.4	22.2
Net earnings / (loss) attributable to shareholders from continuing operations	19.2	1.9	2.0	5.3
Net earnings/(loss) attributable to shareholders	19.6	(8.5)	2.3	6.1
Net earnings / (loss) per share from continuing operations	0.16	(0.6)	0.02	0.03
Net earnings/(loss) per share	0.16	(0.07)	0.02	0.04
Adjusted net earnings	22.0	13.2	5.0	6.5
Adjust net earnings per share	0.18	0.10	0.04	0.04
Total Assets	1,263.1	1,282.6	1,265.6	1,416.0
Long term debt*	472.2	455.0	391.9	461.8
Dividend declared per common share	0.07	0.07	0.07	0.07

* Long term debt includes current and long term portion of debt and convertible debentures

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $58.1 million and $193.1 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar 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 $19.6 million and a net loss of $8.5 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

Disclosure Controls

As of June 30, 2013, APUC carried out an evaluation, under the supervision of and with the participation of APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of June 30, 2013, APUC's disclosure controls and procedures are effective.

Internal controls over financial reporting

Management, including the CEO and the CFO, is responsible for establishing and maintaining internal control over financial reporting. Management, as at the end of the period covered by this interim filing, designed internal control over financial reporting to provide reasonable, but not absolute, assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP. The control framework management used to design the issuer's internal control over financial reporting is that established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

During the six months ended June 30, 2013, APUC acquired the Shady Oaks Wind Facility, the Pine Bluff Water System, and the Columbus/Gainesville Gas System. The financial information for these business acquisitions is included in this MD&A and in Note 3 of the unaudited interim financial statements. National Instrument 52-109 and the U.S. Securities and Exchange Commission provide an exemption, whereby companies undergoing acquisitions, can exclude the acquired business in the year from the scope of testing and assessment of operational effectiveness of controls over financial reporting. Due to the complexity associated with assessing internal controls during integration efforts, the Company plans to utilize the scope exemption as it relates to these acquisitions in management's report on internal controls over financial reporting for the year ending December 31, 2013. The Company also excluded the 2012 acquisitions of EnergyNorth Gas System, Granite State Electric System, Missouri Gas System, Illinois Gas System, Iowa Gas System, and the Sandy Ridge, Minonk and Senate Wind Facilities from its evaluation of the effectiveness of APUC's internal controls over financial reporting as of December 31, 2012 due to the complexity associated with assessing internal controls during integration efforts and the proximity of some of the acquisitions to year-end.

During the quarter ended June 30, 2013, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. APUC continues to implement its internal control structure over the operations of the acquired businesses discussed above.

Critical Accounting Estimates and Polices

APUC prepared its unaudited interim financial statements in accordance with U.S. GAAP. An understanding of APUC's accounting policies is necessary for a complete analysis of results, financial position, liquidity and trends. Significant accounting policies 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, fair value of derivatives, pension and post-retirement benefits and environmental remediation obligation. Management believes there has been no material changes during the three months ended June 30, 2013 to the items discussed in APUC's MD&A and Note 1 of its consolidated financial statements for the year ended December 31, 2012 available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Actual results may differ from these estimates.

Interim Consolidated Balance Sheets

(Unaudited)
(thousands of Canadian dollars)

	June 30, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 37,386**	$ 53,122
Accounts receivable, net of allowance for doubtful accounts of $6,389 and $4,360 (note 4)	**101,608**	87,876
Natural gas in storage	**19,728**	19,279
Supplies and consumables inventory	**7,016**	4,233
Regulatory assets (note 5)	**2,934**	10,644
Due from related parties (note 16)	**814**	816
Prepaid expenses	**12,751**	10,861
Notes receivable (note 6)	**566**	537
Deferred tax asset	**12,883**	10,567
Income tax receivable	**588**	556
Derivative instruments (note 21)	**6,700**	7,020
Assets held for sale (note 15)	**33,007**	102,887
Other current assets	**833**	833
	236,814	309,231
Property, plant and equipment	**2,516,951**	2,086,728
Intangible assets	**56,216**	56,781
Goodwill	**79,364**	61,459
Regulatory assets (note 5)	**130,896**	123,748
Derivative instruments (note 21)	**19,094**	6,230
Long-term investments and notes receivable (note 6)	**36,734**	37,646
Deferred non-current income tax asset	**108,291**	77,497
Other assets	**17,428**	18,917
	$ 3,201,788	$ 2,778,237

Interim Consolidated Balance Sheets (continued)

(Unaudited)

(thousands of Canadian dollars)

	June 30, 2013	December 31, 2012
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	**$ 26,638**	$ 34,271
Accrued liabilities	**86,902**	98,269
Due to related parties (note 16)	**1,839**	1,811
Dividends payable (note 13)	**18,294**	15,498
Regulatory liabilities (note 5)	**14,119**	6,065
Long-term liabilities (note 7)	**8,159**	1,768
Other long-term liabilities	**6,286**	4,352
Advances in aid of construction	**625**	591
Derivative instruments (note 21)	**3,033**	2,211
Environmental obligation (note 18)	**3,277**	-
Preferred series C (note 10)	**896**	-
Liabilities held for sale	**1,282**	1,211
Income tax liability	**1,110**	539
Deferred credits	**6,260**	5,754
Deferred income tax liability	**897**	1,133
	179,617	173,473
Long-term liabilities (note 7)	**1,083,293**	769,058
Convertible debentures (note 8)	**-**	960
Advances in aid of construction	**78,931**	71,626
Regulatory liabilities (note 5)	**88,865**	82,050
Deferred income tax liability	**111,455**	100,798
Derivative instruments (note 21)	**17,833**	15,605
Deferred credits	**21,796**	25,816
Pension and post employment benefits (note 9)	**73,129**	59,246
Environmental obligation (note 18)	**55,482**	56,587
Other long-term liabilities	**20,951**	20,889
Preferred Series C (note 10)	**17,857**	-
	1,569,592	1,202,635
Equity:		
Preferred shares (note 11(b))	**116,546**	116,546
Common shares (note 11(a))	**1,342,774**	1,245,326
Subscription receipts (note 11(a)(ii))	**-**	61,160
Additional paid-in capital	**6,203**	5,224
Deficit	**(459,513)**	(406,143)
Accumulated other comprehensive loss (note 12)	**(62,389)**	(104,867)
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	**943,621**	917,246
Non-controlling interests	**508,958**	484,883
Total Equity	**1,452,579**	1,402,129
Commitments and contingencies (note 18)		
Subsequent events (notes 7 and 18)		
	$ 3,201,788	$ 2,778,237

See accompanying notes to unaudited interim consolidated financial statements

Interim Consolidated Statements of Operations

(Unaudited)

(thousands of Canadian dollars, except per share amounts)

	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Revenue:				
Regulated electricity sales and distribution	**$ 36,353**	$ 15,913	**$ 79,208**	$ 35,299
Regulated gas sales and distributions	**48,582**	-	**138,671**	-
Regulated water reclamation and distribution	**14,808**	12,061	**26,874**	22,654
Non-regulated energy sales	**46,544**	29,836	**93,474**	57,582
Waste disposal fees	**-**	-	**-**	-
Other revenue	**2,463**	909	**3,844**	1,323
	148,750	58,719	**342,071**	116,858
Expenses				
Operating	**44,856**	19,854	**87,903**	39,143
Regulated electricity purchased	**20,958**	9,661	**46,961**	21,444
Regulated gas purchased	**24,890**	-	**83,940**	-
Non-regulated fuel for generation	**3,998**	3,009	**9,022**	7,041
Depreciation of property, plant and equipment	**22,514**	8,383	**43,468**	16,409
Amortization of intangible assets	**1,061**	1,038	**2,100**	2,077
Administrative expenses	**7,348**	5,478	**12,205**	9,859
Gain on foreign exchange	**(835)**	(863)	**(1,318)**	(409)
	124,790	46,560	**284,281**	95,564
Operating income from continuing operations	**23,960**	12,159	**57,790**	21,294
Interest expense	**12,889**	6,202	**25,088**	14,872
Interest, dividend and other income	**(2,166)**	(1,480)	**(4,385)**	(3,596)
Acquisition-related costs	**521**	2,053	**1,014**	4,431
Gain on derivative financial instruments (note 21(b))	**(518)**	694	**(1,904)**	631
	10,726	7,469	**19,813**	16,338
Earnings from continuing operations before income taxes	**13,234**	4,690	**37,977**	4,956
Income tax expense (recovery) (note 14)				
Current	**1,066**	73	**1,256**	144
Deferred	**(177)**	(1,069)	**5,980**	(3,445)
	889	(996)	**7,236**	(3,301)
Earnings from continuing operations	**12,345**	5,686	**30,741**	8,257
(Loss)/earnings from discontinued operations net of tax (note 15)	**(33,890)**	784	**(35,040)**	1,078
Net (loss)/earnings	**(21,545)**	6,470	**(4,299)**	9,335
Net (loss)/earnings attributable to non-controlling interests (note 22)	**(3,454)**	402	**(5,418)**	993
Net (loss)/earnings attributable to shareholders of Algonquin Power & Utilities Corp.	**$ (18,091)**	$ 6,068	**$ 1,119**	$ 8,342
Basic net earnings per share from continuing operations (note 17)	**$ 0.08**	$ 0.03	**$ 0.18**	$ 0.05
Basic net loss per share from discontinued operations (note 17)	**(0.17)**	0.01	**(0.17)**	0.01
Basic net earnings per share (note 17)	**(0.09)**	0.04	**0.01**	0.06
Diluted net earnings per share from continuing operations (note 17)	**0.08**	0.03	**0.18**	0.05
Diluted net loss per share from discontinued operations (note 17)	**(0.16)**	0.01	**(0.17)**	0.01
Diluted net earnings per share (note 17)	**$ (0.09)**	$ 0.04	**$ 0.01**	$ 0.06

See accompanying notes to unaudited interim consolidated financial statements

Interim Consolidated Statements of Comprehensive Income (Loss)

(Unaudited)

(thousands of Canadian dollars)

	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Net earnings	**$ (21,545)**	$ 6,470	**$ (4,299)**	$ 9,335
Other comprehensive income (loss):				
Foreign currency translation adjustment, net of tax of $2,776 and $3,351 (2012 - $Nil), respectively (notes 21(b)(iii) and (c))	**45,534**	4,887	**70,878**	49
Change in fair value of cash flow hedge, net of tax recovery of $1,973 and $2,711 (2012 - $Nil), respectively	**2,951**	144	**4,152**	144
Change in unrealized pension and other post-retirement expense, net of tax recovery of $5 and $10 (2012 - $Nil), respectively (note 9)	**10**	-	**23**	(4)
Other comprehensive income (loss), net of tax	**48,495**	5,031	**75,053**	189
Comprehensive income (loss)	**26,950**	11,501	**70,754**	9,524
Comprehensive income (loss) attributable to the non-controlling interest	**17,538**	1,188	**27,157**	1,043
Comprehensive income (loss) attributable to shareholders of Algonquin Power & Utilities Corp.	**$ 9,412**	$ 10,313	**$ 43,597**	$ 8,481

See accompanying notes to unaudited interim consolidated financial statements

Interim Consolidated Statement of Equity
(Unaudited)
(thousands of Canadian dollars)

For the six months ended June 30, 2013

	Common Shares	Preferred Shares	Subscription Receipts	Additional paid-in capital	Accumulated Deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2012	$ 1,245,326	$ 116,546	$ 61,160	$ 5,224	$ (406,143)	$ (104,867)	$ 484,883	$ 1,402,129
Net (loss)/earnings					1,119		(5,418)	(4,299)
Other comprehensive income	-	-	-	-	-	42,478	32,575	75,053
Dividends declared and distributions to non-controlling interests	-	-	-	-	(30,172)	-	(3,081)	(33,253)
Dividends and issuance of shares under dividend reinvestment plan	5,820	-	-	-	(5,820)	-	-	-
Exercise and conversion of subscription receipts	90,468	-	(90,468)	-	-	-	-	-
Issuance of subscription receipts	-	-	29,308	-	-	-	-	29,308
Conversion and redemption of convertible debentures	960	-	-	-	-	-	-	960
Issuance of common shares under employee share purchase plan	200	-	-	-	-	-	-	200
Stock compensation expense	-	-	-	979	-	-	-	979
Preferred Series C shares	-			-	(18,497)	-	-	(18,497)
Balance, June 30, 2013	$ 1,342,774	$ 116,546	$ -	$ 6,203	$ (459,513)	$ (62,389)	$ 508,958	$ 1,452,580

See accompanying notes to unaudited interim consolidated financial statements

Interim Consolidated Statements of Cash Flows

(Unaudited)

(thousands of Canadian dollars)

	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Cash provided by (used in):				
Operating Activities:				
Net earnings from continuing operations	**$ 12,345**	$ 5,686	**$ 30,741**	$ 8,257
Adjustments and items not affecting cash:				
Depreciation of property, plant and equipment	**22,514**	8,383	**43,468**	16,409
Amortization of intangible assets	**1,061**	1,038	**2,100**	2,077
Other amortization	**287**	573	**863**	1,121
Deferred taxes	**(177)**	(1,068)	**5,980**	(3,445)
Unrealized (gain)/loss on derivative financial instruments	**(1,058)**	291	**(2,202)**	(830)
Share-based compensation	**559**	618	**979**	846
Pension and post retirement expense	**1,047**	-	**1,807**	-
Unrealized foreign exchange loss	**-**	778	**-**	778
Changes in non-cash operating items (note 19)	**23,332**	185	**(27,663)**	1,521
Changes in non-cash operating items from discontinued operations (note 19)	**473**	(1,865)	**(481)**	(2,939)
Cash provided from discontinued operations	**(3,006)**	2,636	**(2,898)**	4,598
	57,377	17,255	**52,694**	28,393
Financing Activities:				
Cash dividends on common shares	**(12,263)**	(8,602)	**(24,676)**	(16,483)
Cash dividends on preferred shares	**(1,350)**	-	**(2,700)**	-
Cash distributions to non-controlling interests	**(2,903)**	(133)	**(3,081)**	(258)
Issuance of common shares	**82**	60,167	**29,508**	60,167
Proceeds from subscription receipts	**-**	15,000	**-**	15,000
Deferred financing costs	**(10)**	(1,253)	**(324)**	(1,828)
Increase in long-term liabilities	**364,042**	66,029	**392,654**	66,029
Decrease in long-term liabilities	**(213,336)**	(327)	**(258,063)**	(656)
Increase in advances in aid of construction	**2,327**	1,064	**2,477**	1,103
Increase in other long-term liabilities	**-**	171	**-**	265
Decrease in other long-term liabilities	**(301)**	(92)	**(1,057)**	(160)
	136,288	132,024	**134,738**	123,179
Investing Activities:				
Decrease/(increase) in restricted cash	**(454)**	(94)	**(648)**	680
Increase in other assets	**(86)**	(2,281)	**(1,783)**	(3,545)
Distributions received in excess of equity income	**504**	(433)	**818**	(168)
Receipt of principal on notes receivable	**133**	119	**203**	235
Additions to property, plant and equipment	**(39,377)**	(19,024)	**(55,785)**	(29,668)
Additions to intangibles	**-**	(60)	**-**	(1,060)
Acquisitions of operating entities (note 3(a),(b), and (e))	**(159,486)**	(30,287)	**(172,189)**	(30,287
Proceeds from sale of discontinued operations	**24,968**	204	**24,968**	204
	(173,798)	(51,856)	**(204,416)**	(63,609)
Effect of exchange rate differences on cash	**670**	52	**1,248**	8
Increase/(decrease) in cash and cash equivalents from continuing operations	**(1,425)**	94,635	**(37,806)**	83,169
Increase in cash and cash equivalents from discontinued operations (note 15)	**21,962**	2,840	**22,070**	4,802
Cash and cash equivalents, beginning of the period	**16,849**	63,382	**53,122**	72,887
Cash and cash equivalents, end of the period	**$ 37,386**	$ 160,858	**$ 37,386**	$ 160,858
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest expense	**$ 7,749**	$ 4,448	**$ 20,966**	$ 11,604
Cash paid during the period for income taxes	**$ 352**	$ 160	**$ 635**	$ 251
Non-cash transactions				
Property, plant and equipment acquisitions in accruals	**$ 6,146**	$ 2,561	**$ 6,146**	$ 2,561

See accompanying notes to consolidated financial statements

Notes to the Unaudited Interim Consolidated Financial Statements

Three and six months ended June 30, 2013 and 2012

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

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

(a) 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 follow disclosures required under Regulation S-X Rule 10-01, Interim Financial Statements 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, 2012 except for accounting policies adopted for disclosure about offsetting assets and liabilities, comprehensive income and revenue recognition for Liberty Energy (California) ("Calpeco Electric System") (note 1(c), (d) and note 2 below).

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 and industry characteristics within a utility serving territory. Calpeco Electric System has historically experienced higher demand for electricity during the winter rather than during the summer period since the utility serves a number of ski hills and resorts in its service territory. Starting in 2013, as a result of the decoupling mechanism approved by its regulator (note 5), Calpeco Electric System's earnings are no longer affected by differences in delivery volumes from levels assumed when rates were approved.

(b) Basis of consolidation

The accompanying unaudited interim consolidated financial statements of APUC include the accounts of APUC and its wholly owned subsidiaries and variable interest entities ("VIEs") where the Company is the primary beneficiary. Intercompany transactions and balances have been eliminated.

(c) Recognition of revenue

Beginning in 2013, in accordance with the revenue decoupling mechanism approved by its regulator, Calpeco Electric System is required to record approved annual delivery revenues evenly over its fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers.

(d) Right of offset

The fair value gains or losses recognized on derivative instruments executed with the same counterparty under a master netting arrangement are presented on a gross basis on the Consolidated Balance Sheet.

2. Changes in Accounting Policies and Estimates

(a) Recent accounting pronouncements

The FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities and ASU 2013-01 Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. These newly issued accounting standards require an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the balance sheet including financial instruments and transactions executed under a master netting or similar arrangement. The standards were issued to enable users of the financial statements to understand the effects or potential effects of such arrangements on an entity's financial position. The adoption of these standards as at January 1, 2013 did not have a material impact on the Company's interim consolidated financial statements.

The FASB issued ASU 2013-02, Comprehensive Income (Topic 220). This newly issued accounting standard requires an entity to provide certain information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes to the financial statements, the effect of, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net

2. **Changes in Accounting Policies and Estimates (continued)**

(a) Recent accounting pronouncements (continued)

income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. Other than the additional disclosure (note 12), the adoption of this standard did not have a material impact on the Company's interim consolidated financial statements.

(b) Recent accounting pronouncements not yet adopted

The 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 tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except in some specific situations. This ASU is required to be applied prospectively for fiscal years, and interim periods beginning after December 15, 2013. The adoption of this standard is not expected to have an impact 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 permit 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. This ASU is required to be applied prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. The adoption of this standard is not expected to have an impact the Company's financial position or results of operations.

3. **Business acquisitions and developments projects**

(a) Acquisition of Shady Oaks wind power facility

Effective January 1, 2013, APCo acquired the 109.5 megawatt ("MW") Shady Oaks wind powered generating facility ("Shady Oaks") by assuming the existing long-term debt of approximately U.S. $150,000 for no additional cash. 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. The energy and basis related price adjustment will be based on the project's experience from January 1, 2013 to June 30, 2014.

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

Cash	$	4,683
Working capital		2,653
Property, plant and equipment		121,143
Deferred tax asset		22,790
Long term debt		(149,235)
Asset retirement obligation		(1,363)
Total net assets acquired	$	671

The determination of the fair value of assets and liabilities acquired has been based upon management's preliminary estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. The Company has not completed the fair value measurements, particularly that of the contingent consideration. 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 estimated purchase price was reduced by U.S. $3,291 as at June 30, 2013 to reflect the latest information available.

Property, plant and equipment are amortized on a straight line basis over the lives of the assets, which have a weighted average life of 38 years.

Shady Oaks earns revenue from the sale of electricity and renewable energy credits and from capacity payments. Shady Oaks recognizes revenue from the sale of electricity and renewable energy credits ("RECs") based upon the output delivered at rates specified under a long-term power purchase agreement with Commonwealth Edison Company ("ComEd"). Shady Oaks has contracted to sell approximately 310,000 MW hours of electricity (and associated RECs) to ComEd each year, commencing June 1, 2012, under this long-term power purchase agreement. On March 29, 2013, ComEd issued curtailment notice reducing the annual contract quantity for the delivery year from June 1, 2013 to May 31, 2014 to 252,617 MW hours. Electricity and associated renewable energy credits not sold to ComEd will be sold into wholesale electric markets.

Shady Oaks contributed revenue of $4,282 and $9,434 and net earnings of $956 and $2,660 to APUC's consolidated financial results for the three and six months ended June 30, 2013. The disclosure of pro forma revenue and earnings has been deemed impracticable as Shady Oaks being a newly constructed wind power generation facility only achieved commercial operations in the second half of 2012 and therefore had little operations prior to the acquisition by APCo.

All costs related to the acquisition have been expensed in the unaudited interim Consolidated Statement of Operations.

3. Business acquisitions and developments projects (continued)

(b) Acquisition of Pine Bluff Water System

On February 1, 2013, Liberty Utilities acquired United Water Arkansas Inc. a regulated water distribution utility (the "Pine Bluff Water System") located in Pine Bluff, Arkansas. Total purchase price for the Pine Bluff Water System is approximately $27,533 (U.S. $27,600), subject to certain working capital and other closing adjustments. The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed including working capital adjustments at the acquisition date:

Cash	$	8
Working capital		813
Property, plant and equipment		28,371
Regulatory assets		957
Goodwill		4,656
Other liabilities		(304)
Pension		(3,665)
Deferred income tax liability, net		(2,931)
Total net assets acquired	$	27,905

The determination of the fair value of assets and liabilities acquired has been based upon management's preliminary estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. The Company has not yet completed the fair value measurements as at June 30, 2013. In particular, fair value estimates of the OPEB obligation have not yet been recorded. In addition, the purchase agreement provides for a final purchase price adjustment based on agreed working capital and rate base balances at the acquisition date. 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.

Goodwill represents the excess of the fair value of the consideration paid over the fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include expected future cash flows, potential operational synergies, the utilization of technology, and cost savings opportunities in the delivery of certain shared administrative and other services. The goodwill related to the Pine Bluff Water System has been reported under the Liberty Utilities (Central) segment.

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 life of the Pine Bluff Water System assets is 40 years.

All costs related to the acquisition have been expensed through the unaudited interim Consolidated Statement of Operations.

Pine Bluff Water System contributed revenue of $2,361 and $3,806 and net earnings of $353 and $586 to the Company's consolidated financial results for the three and six months ended June 30, 2013.

(c) Acquisition of Columbus/Gainesville Gas System

On April 1, 2013, Liberty Utilities acquired certain regulated natural gas distribution utility assets (the "Columbus/Gainesville Gas System") located in the State of Georgia from Atmos Energy Corporation. The total purchase price for the Columbus/Gainesville Gas System is approximately $155,578 (U.S. $153,000), subject to certain working capital and other closing adjustments.

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

Working capital	$	7,775
Property, plant and equipment		147,157
Goodwill		8,560
Deferred income tax asset, net		2,119
Derivative asset		231
Regulatory liabilities		(3,612)
Other liabilities		(1,853)
Pension and OPEB		(4,615)
Derivative liabilities		(184)
Total net assets acquired	$	155,578

The determination of the fair value of assets and liabilities acquired has been based upon management's preliminary estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. The Company has not yet completed the fair value measurements as at June 30, 2013. In addition, the purchase agreement provides for a final purchase price adjustment based on agreed working capital and rate base balances at the acquisition date. 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.

Goodwill represents the excess of the fair value of the consideration paid over the fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include expected future cash flows, potential operational synergies, the utilization of technology, and cost savings opportunities in the delivery of certain shared administrative and other services. The goodwill related to the Columbus/Gainesville Gas System has been reported under the Liberty Utilities (East) segment.

3. Business acquisitions and developments projects (continued)

(c) Acquisition of Columbus/Gainesville Gas System (continued)

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 life of the Columbus/Gainesville Gas System assets is 55 years.

All costs related to the acquisition have been expensed through the unaudited interim Consolidated Statement of Operations.

Columbus/Gainesville Gas System contributed revenue of $12,668 and $12,668 and net earnings of $1,996 and $1,996 to the Company's consolidated financial results for the three and six months ended June 30, 2013.

The supplemental pro forma financial information below was prepared using the acquisition method of accounting and is based on the historical financial information of APUC and Columbus/Gainesville Gas System reflecting results of operations for the three and six months ended June 30, 2013 and 2012 on a comparative basis as though the aforementioned companies were combined as of January 1, 2012. The acquiree's pre-acquisition results have been added to APUC's historical results, and the totals have been adjusted for the pro forma effects of acquisition-related costs, interest expense related to the financing of the business combinations, and related income taxes.

Pro forma	**Three months ended June 30,**		**Six months ended June 30,**	
	2013	**2012**	**2013**	**2012**
Total revenue from continuing operations	$ 148,750	$ 68,231	$ 363,936	$ 144,370
Net earnings from continuing operations	11,994	6,263	32,927	11,014
Basic net earnings from continuing operations per share	0.08	0.04	0.19	0.07
Diluted net earnings from continuing operations per share	0.08	0.04	0.19	0.07

The above unaudited pro forma financial information is presented for informational purposes only and does not purport to represent what the results would have been had theacquisition closed on the date assumed, nor is it necessarily indicative of the results that may be expected in future period.

d) Acquisition of solar energy project

On January 4, 2012, APCo acquired rights to develop a 10 MWac solar project located near Cornwall, Ontario which has been granted a Feed-in-Tariff contract by the Ontario Power Authority ("OPA") for a 20 year term at a rate of $443/MWh. The consideration for the development rights is $4,500 plus additional contingent consideration of $3,500 based on achieving certain construction milestones. As at June 30, 2013, the Company has paid a total of $3,000 based on achieved milestones. The transaction has been recorded as a purchase of intangible assets.

(e) Agreement to acquire New England Gas Company

On February 11, 2013, Liberty Utilities entered into an agreement with The Laclede Group, Inc. to assume the rights to purchase the assets of New England Gas Company ("New England Gas") located in the State of Massachusetts. Total purchase price for the New England Gas net assets is approximately U.S. $74,000, 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 second half of 2013.

(f) Acquisition of New Hampshire electric and gas utilities

After the December 31, 2012 consolidated financial statements were issued, the Company received additional information which was used to refine the estimates for fair value of assets acquired and liabilities assumed for the New Hampshire electric and gas utilities. The carrying value of those assets and liabilities were retrospectively adjusted to the amounts detailed in the table below. As a result, the total consideration was reduced by $9,277, working capital acquired was reduced by $9,697 and goodwill was increased by $957.

3. **Business acquisitions and developments projects (continued)**

(f) Acquisition of New Hampshire electric and gas utilities (continued)

	Granite State	EnergyNorth	Total
Cash	$ 395	$ -	$ 395
Restricted cash	3,252	-	3,252
Working capital	1,916	15,420	17,336
Property, plant and equipment	86,935	256,305	343,240
Regulatory assets	31,683	87,126	118,809
Deferred financing	31	-	31
Other assets	-	83	83
Goodwill	-	28,537	28,537
Customer deposits	(661)	(962)	(1,623)
Long-term debt	(15,188)	-	(15,188)
Other long-term liabilities	(1,468)	(3,287)	(4,755)
Advances in aid of construction	-	(86)	(86)
Derivative liabilities	-	(2,598)	(2,598)
Regulatory liabilities	(5,533)	(27,456)	(32,989)
Pension and OPEB	(19,108)	(29,197)	(48,305)
Environmental obligation	-	(54,431)	(54,431)
Deferred income tax liabilities, net	-	(61,484)	(61,484)
	82,254	207,970	290,224
Less: Cash acquired	(395)	-	(395)
Total net assets acquired	$ 81,859	$ 207,970	$ 289,829

4. **Accounts receivable**

Accounts receivable as of June 30, 2013, includes unbilled revenue of $15,201 (December 31, 2012 - $22,658) in the regulated utilities. The unbilled revenue is an estimate of the amount of utility revenue earned since the date the meters were last read.

5. **Regulatory matters**

The Company's regulated utility operating companies owned by Liberty Utilities 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 U.S. Financial Accounting Standards Board 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.

On November 29, 2012, Calpeco Electric System's regulator approved an All Parties General Rate Case Settlement. As an element of the decision, a revenue decoupling mechanism and a vegetation management memorandum account was agreed upon. The revenue decoupling mechanism will isolate base revenues from fluctuations caused by weather and economic factors. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses to customers, one of the largest expenses of the utility.

5. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

		June 30, 2013		December 31, 2012
Regulatory assets:				
Environmental costs	$	62,310	$	59,789
Pension and other post employment benefits		50,030		47,838
Storm costs deferral		6,575		6,726
Energy costs adjustment		1,249		7,962
Derivative assets		1,303		1,731
Rate case costs		2,468		2,398
Vegetation management		1,946		2,082
Alternative revenue program		98		272
Rate adjustment mechanism		73		-
Asset retirement obligation		1,417		1,095
Other		6,361		4,499
Total regulatory assets		133,830		134,392
Less current regulatory assets		(2,934)		(10,644)
Non-current regulatory assets	$	130,896	$	123,748
Regulatory liabilities				
Cost of removal	$	67,706	$	58,852
Rate-base offset		15,573		15,541
Energy costs adjustment		16,661		11,706
Pension and other post employment benefits		1,064		1,127
Derivative liabilities		14		616
Other		1,966		273
Total regulatory liabilities		102,984		88,115
Less current regulatory liabilities		(14,119)		(6,065)
Non-current regulatory liabilities	$	88,865	$	82,050

6. Long-term investments and notes receivable

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

		June 30, 2013		December 31, 2012
Long –term investments				
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	$	4,851	$	4,926
25% of Class B non-voting shares of Cochrane Power Corporation		4,048		4,669
45% interest in the Algonquin Power (Rattle Brook) Partnership		4,032		3,884
50% interest in the Valley Power Partnership		1,371		1,767
Other		321		180
Total long-term investments	$	14,623	$	15,426
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% and 4.91%, respectively		2,195		2,448
Silverleaf resorts loan, interest at 15.48% maturing July 2020		2,125		2,010
Other		204		146
		22,677		22,757
Less: current portion		(566)		(537)
Total long-term notes receivable	$	22,111	$	22,220
Total long-term investments and notes receivable	$	36,734	$	37,646

7. Long-term liabilities

Long-term liabilities consist of the following:

		June 30, 2013		December 31, 2012
APCo				
Revolving credit facility	$	69,516	$	27,074
Senior debt Shady Oaks		131,475		-
Senior Unsecured notes		149,915		149,910
Senior Unsecured notes		134,822		134,807
Senior debt Long Sault Rapids		37,652		38,136
Sanger bonds		20,194		19,102
Senior debt Chute Ford		3,595		3,763
Liberty Utilities				
Revolving credit facility		31,554		27,360
Unsecured term facility		105,180		-
Liberty Utilities Co. Senior unsecured notes		252,432		223,852
California Pacific Electric Company, LLC Senior unsecured notes		73,626		69,643
Liberty Water Co. Senior unsecured notes		52,590		49,745
Granite State Electric Company Senior Unsecured notes		15,777		14,924
Litchfield Park Service Company IDABonds		11,888		11,269
Bella Vista Water Water Infrastructure Financing Authority of Arizona loans		1,236		1,241
		1,091,452		770,826
Less: current portion		(8,159)		(1,768)
	$	1,083,293	$	769,058

APCo

Effective January 1, 2013, concurrent with the acquisition of Shady Oaks (note 3(a)), APCo assumed existing long-term debt of approximately U.S. $150 million. A portion of the long-term debt of U.S. $25,000 was repaid on June 30, 2013 and another current portion of U.S. $3,000 is payable on November 15, 2013. The semi-annual principal repayment schedule for the following 11 years ranges from U.S., $3,000 to U.S. $6,000 with a final repayment of U.S. $20,000 in 2025. This debt may be repaid in whole or in part at anytime without penalty and bears interest at Libor plus 280 basis points.

Liberty Utilities

On March 14, 2013, Liberty Utilities issued U.S. $15,000 of senior unsecured notes through a private placement in connection with the acquisition of the Pine Bluff Water System (note 3 (b)). The notes bear interest at 4.14% and mature in 10 years.

On March 14, 2013, Liberty Utilities entered into a variable rate unsecured U.S. $100,000 term facility with a U.S. Bank. On April 1, 2013, Liberty Utilities drew U.S. $100,000 from the facility to fund a portion of the acquisition of the Columbus/Gainesville Gas System (note 3(c)). Subsequent to quarter end on July 31, 2013, Liberty Utilities issued U.S. $125,000 of senior unsecured notes through a private placement in three tranches: U.S. $25,000, bearing an interest rate of 3.23%, maturing July 31, 2020; U.S. $75,000, bearing an interest rate of 3.86%, maturing July 31, 2023; and, U.S. $25,000, bearing an interest rate of 4.26%, maturing July 31, 2028. The proceeds of the private placement financing were used to repay the U.S. $100,000 term facility and reduce the drawn amount on Liberty's revolving credit facility. As a result of its long term refinancing subsequent to quarter end, the term facility is classified as non-current as at June 30, 2013.

8. Convertible debentures

On January 2, 2013, the remaining principal amount of $960 of Series 3 Debentures was redeemed for 150,816 shares of APUC (note 11(a)(i)).

9. Pension and other post-retirement benefits

The following table lists the components of net benefit costs for the pension plans and Other Post Employment Benefits ("OPEB") recorded as part of administrative expenses in the unaudited interim Consolidated Statements of Operations. The Consolidated Statements of Operations reflect the employee benefit costs for businesses acquired from the date of acquisition. The portion of employee benefit costs capitalized as cost of construction is insignificant.

	Pension benefits							
	Three months ended June 30,				Six months ended June 30,			
		2013		2012		2013		2012
Service cost	$	729	$	81	$	1,380	$	162
Interest cost		1,064		6		2,049		11
Expected return on plan assets		(1,027)		(4)		(1,948)		(9)
Amortization of net actuarial loss		2		-		4		-
Amortization of regulatory assets/liabilities		122		1		242		1
Net benefit cost	$	890	$	84	$	1,727	$	165

9. **Pension and other post-retirement benefits (continued)**

	OPEB			
	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
Service cost	$ 388	$ -	$ 675	$ -
Interest cost	348	-	653	-
Expected return on plan assets	(149)	-	(297)	-
Amortization of net actuarial loss	10	-	19	-
Amortization of regulatory assets/liabilities	52	-	103	-
Net benefit cost	$ 649	$ -	$ 1,153	$ -

10. **Mandatorily redeemable Series C preferred shares**

Effective January 1, 2013, the Company issued 100 redeemable Series C preferred shares in exchange for 100 Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APCo and the legal owner of the St. Leon facility (note 11(b)). Thirty six of the Series C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 for $53,400 per share and have a contractual cumulative cash dividend paid quarterly until the date of redemption based on a prescribed payment schedule detailed below. These shares are accounted for as liabilities in the unaudited interim consolidated financial statements. The cumulative dividends are indexed in proportion to the increase in CPI over the term of the shares. The dividend is intended to approximate the distributions that otherwise would have accrued to holders of Class B limited partnership units.

Upon redemption in 2031, the shares will be redeemed for $53,400 per share. The Series C preferred shares are convertible into common shares at the option of the holder and the Company, at any time after May 20, 2031 and before June 19, 2031, at a conversion price of $53,400 per share.

The Series C preferred shares were initially measured at their estimated fair value of $18,497 based on the present value of the expected contractual cash flows including dividends and redemption amount, discounted at a rate of 5.0%. The recognition of the initial fair value of $18,497 resulted in an adjustment to equity of the shareholders of the Company as the Class B shares had a nominal carrying amount prior to the exchange. The Series C preferred shares are accounted for under the effective interest method, resulting in accretion of interest expense over the term of the shares. Dividend payments are recorded as a reduction of the Series C preferred share carrying value.

Estimated dividend and redemption payments due in the next five years and thereafter are:

2013	$ 619
2014	1,109
2015	1,077
2016	946
2017	895
Thereafter to 2031	21,985
Redemption amount	5,340
	31,971
Less amounts representing interest	(13,218)
	18,753
Less current portion	(896)
	$ 17,857

11. **Shareholders' capital**

(a) Common shares

Number of common shares:

	June 30, 2013
Common shares, December 31, 2012	188,763,486
Conversion and redemption of convertible debentures (i)	150,816
Conversion of subscription receipts (ii)	15,223,016
Issuance of shares under the dividend reinvestment and employee share purchase plans	860,608
Common shares, June 30, 2013	204,997,926

(i) Conversion and redemption of convertible debentures

On January 2, 2013, the remaining principal amount of $960 Series 3 Debentures was redeemed for 150,816 common shares of APUC.

(ii) Subscription receipts

On December 10, 2012, in connection with the acquisition of Senate Wind Project and Minonk Wind Project, the Company received $45,000 from Emera Inc. ("Emera") relating to the exercise of 7,842,016 subscription receipts at a price of $5.74

11. Shareholders' capital (continued)

per subscription receipt pursuant to a subscription receipt agreement. The subscription receipts were converted to 7,842,016 common shares on February 14, 2013.

On December 21, 2012, in connection with the acquisition of Emera's non-controlling interest in Calpeco Electric System, the Company received $38,756 from Emera relating to the exercise of 8,211,000 subscription receipts at a price of $4.72 per subscription receipt pursuant to a subscription receipt agreement. On December 27, 2012, Emera exercised 4,790,000 of these subscription receipts and the Company issued 4,790,000 common shares in exchange. On February 14, 2013, the balance of 3,421,000 subscription receipts were exercised by Emera and the Company issued 3,421,000 common shares.

On March 26, 2013, the Company issued 3,960,000 common shares at a price of $7.40 per share to Emera pursuant to a subscription receipt agreement. The $29,308 cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisition of the Columbus/Gainesville Gas System on April 1, 2013 (note 3 (c)).

Following the above noted subscription receipts transactions, as of June 30, 2013 all subscriptions receipts had been exercised for cash and converted to common shares.

(b) Preferred shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board of Directors of APUC. APUC has 4,800 Series A Preferred shares outstanding, at an average price of $25 per share.

(c) Share-based compensation

On March 13, 2013, the Board approved the grant of 816,402 options to senior executives of the Company. The options allow for the purchase of common shares at a price of $7.72, the market price of the underlying common share at the date of grant.

One-third of the options vest on each of January 1, 2014, 2015 and 2016. Options may be exercised up to eight years following the date of grant.

During the six months ended June 30, 2013, 11,669 Deferred Share Units ("DSU") were issued pursuant to the election of the Directors to defer a percentage of their 2013 Director's fee in the form of DSUs.

For the three and six months ended June 30, 2013, APUC recorded $563 and $987 (2012 - $617 and $846) 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 Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at June 30, 2013, total unrecognized compensation costs related to non-vested options and share unit awards were $3,012 and $153 respectively, and are expected to be recognized over a period of 1.82 years and 1.35 years respectively.

12. Accumulated other comprehensive loss

Changes in accumulated other comprehensive loss by component, net of tax:

	Foreign currency cumulative translation	Unrealized gain on cash flow hedges	Pension and post-retirement actuarial loss	Total
Balance, December 31, 2012	$ (105,959)	$ 3,593	$ (2,501)	$ (104,867)
Other comprehensive income (loss) before reclassifications	38,303	3,981	-	42,284
Amounts reclassified from accumulated other comprehensive loss	-	171	23	194
Net current period other comprehensive income	38,303	4,152	23	42,478
Balance, June 30, 2013	$ (67,656)	$ 7,745	$ (2,478)	$ (62,389)

13. Cash dividends

On June 28, 2013, an initial dividend of $0.28125 per share totaling $1,350, Series A, was paid in cash to Preferred Share, Series A holders of record on June 14, 2013.

The dividends per common share declared per share for the three and six months ending June 30, 2013 was $0.085 and $0.1625 respectively (2012 - $0.07 and $0.14).

14. Income taxes

For the six months ended June 30, 2013, the Company's overall effective tax rate was different than the statutory rate of 26.50% (2012 - 26.25%) due primarily to recognition of deferred credits, higher tax rates in U.S. subsidiaries, minority interest partner's tax expenses, inter-corporate dividends, and non deductible expenses.

Included in deferred income tax recoveries for the three and six months ended June 30, 2013 is $1,198 and $3,514 (2012- $771 and $1,518) related to the recognition of deferred credits from the utilization of deferred income tax assets respectively.

15. Sale of 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. $1,098, net of tax recovery of U.S. $1,661. The sale of the last small U.S. hydroelectric generating facilities is expected to close in the fourth quarter of 2013 for $3,600.

15. Sale of Facilities (continued)

During the quarter, the Company initiated a strategic review of the Company's business plan and opportunities available for its Energy From Waste ("EFW") facility. As a result of the review, the Company decided during the quarter to sell the facility and expects the sales process to be concluded within the next 12 months. Accordingly, the assets of EFW are presented as assets held for sale on the unaudited interim Balance Sheet. In the second quarter of 2013, the net assets of EFW were written down to their estimated fair value less cost of sale which resulted in a write down of the net assets of $47,651 before tax, or $35,738 net of tax of $11,913. The determination of the fair value of the net assets of EFW has been based upon management's preliminary estimates and assumptions considering present conditions and management's planned course of action. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

In August 2012, APCo sold a small U.S. Hydro facility for gross proceeds of $350 for a loss on sale, net of tax of $253.

The operating results from these facilities are disclosed as discontinued operations on the interim consolidated statements and prior periods have been reclassified to conform to this presentation.

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

	Three months ended 2013	Three months ended 2012
Non-regulated energy sales	$ 2,718	$ 2,486
Waste disposal fees	2,037	4,179
Other and interest income	94	7
Operating and administrative expenses	(5,438)	(3,990)
Depreciation of property, plant and equipment	(928)	(1,640)
Interest expense	(43)	(46)
Gain on sale	1,155	-
Write-down of assets	(47,651)	-
Income (loss) from discontinued operations, before income taxes	(48,056)	996
Income tax recovery(expense)	14,166	(212)
Income (loss) from discontinued operations, net of income taxes	(33,890)	784
Add:		
Depreciation of property, plant and equipment	928	1,640
Write-down of assets	47,651	-
Net proceeds from disposition	22,052	204
Contingent liability	(613)	-
Income tax recovery (expense)	(14,166)	212
Increase in cash and cash equivalents from discontinued operations	$ 21,962	$ 2,840

	Six months ended 2013	Six months ended 2012
Non-regulated energy sales	$ 6,056	$ 5,357
Waste disposal fees	3,950	7,606
Other and interest income	253	13
Operating and administrative expenses	(10,696)	(8,271)
Depreciation of property, plant and equipment	(2,483)	(3,259)
Interest expense	(87)	(107)
Gain on sale	1,155	-
Write-down of assets	(47,651)	-
Income (loss) from discontinued operations, before income taxes	(49,503)	1,339
Income tax recovery(expense)	14,463	(261)
Income (loss) from discontinued operations, net of income taxes	(35,040)	1,078
Add:		
Depreciation of property, plant and equipment	2,483	3,259
Write-down of assets	47,651	-
Net proceeds from disposition	22,052	204
Contingent liability	(613)	-
Income tax recovery (expense)	(14,463)	261
Increase in cash and cash equivalents from discontinued operations	$ 22,070	$ 4,802

15. Sale of Facilities (continued)

Assets held-for-sale was as follows:

	June 30, 2013	December 31, 2012
Property, plant and equipment	$ 29,945	$ 100,377
Accounts receivable and prepaids	3,062	2,510
Total	$ 33,007	$ 102,887

Liabilities held-for-sale was as follows:

	June 30, 2013	December 31, 2012
Accounts payable and accrued liabilities	$ 1,282	$ 1,211

16. Related party transactions

Certain executives of APUC are shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of the Company. A member of the Board of Directors of APUC is an executive at Emera.

Transactions with APMI and Senior Executives

APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the three and six months ended June 30, 2013 were $84 and $168 (2012 - $82 and $164).

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. During the three and six months ended June 30, 2013, APUC incurred costs in connection with the use of the aircraft of $78 and $146 (2012 - $104 and $164) and amortization expense related to the advance against expense reimbursements of $nil (2012 - $88 and $155). At June 30, 2013, the remaining amount of the advance was $nil (December 31, 2012 - $nil).

Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon LP, a subsidiary of APUC and the legal owner of the St. Leon facility. The related holders of the Class B units received cash distributions of $nil for the three and six months ended June 30, 2013 (2012 - $80 and $155). On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the Class B units (note 10).

APUC provided supervisory management services on a cost recovery basis to a hydroelectric generating facility not owned by APUC where Senior Executives hold an equity interest.

Rattle Brook is a hydroelectric generating facility in which APUC owns a 45% interest and Senior Executives hold an equity interest in. Rattle Brook is operated on a cost recovery basis by an entity which is partially owned by Senior Executives.

APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. In 2011, APUC acquired APMI's interest in this royalty. An amount of $600 has been accrued as an estimate of the final fee owed to APMI.

Transactions with APMI and Senior Executives (continued)

As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee. An amount of U.S. $550 has been accrued as an estimate of the final fee owed to APMI.

During 2007, APUC allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee of $1,800. As part of its role in the process, APUC has agreed to pay APMI a fee of $100 which has been accrued as an estimate of the final fee owed to APMI.

As at June 30, 2013, due from related parties include $814 (December 31, 2012 - $816) owed to APUC from APMI and due to related parties include $1,839 (December 31, 2012 - $1,811) owed to APMI. These amounts arise from the transactions described above.

Long Sault is a hydroelectric generating facility in which APUC acquired its interest by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the after tax equity cash flows commencing in 2014.

In March 2012, APUC and APMI's Senior Executives (the "Parties") reached a term sheet agreement to resolve a number of the historic joint business associations between the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed before the end of 2013.

Under the term sheet, it is proposed that APUC will exchange its 45% interest in the 4MW Rattle Brook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement is based on an assumed transaction date of January 1, 2012 and also settles outstanding fees owing to APMI.

Transactions with Emera

In 2011, a subsidiary of Emera provided lead market participant services for fuel capacity and forward reserve markets to ISO NE for the Windsor Locks facility. During the three and six months ended June 30, 2013 APUC paid U.S. $nil (2012 – U.S. $69 and $160) in relation to this contract. In 2011, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

16. Related party transactions (continued)

For the three and six months ended June 30, 2013, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $1,527 and $3,162 (2012 – U.S. $1,477 and $2,990). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S. $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.

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

17. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares outstanding during the year. Diluted net income 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, performance share units ("PSUs"), deferred share units ("DSUs"), shareholders' rights and convertible debentures. The dilutive effect of outstanding stock options, PSUs, DSUs and shareholders' rights is reflected in diluted earnings per share by application of the Treasury Stock Method while the dilutive effect of convertible debentures is reflected in diluted earnings per share by application of the As If Converted Method.

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

	Three months ended June 30,		Six months ended June 30,	
	2013	**2012**	**2013**	**2012**
Net(loss)/earnings attributable to shareholders of APUC	$ (18,091)	$ 6,068	$ 1,119	$ 8,342
Series A preferred shares dividend	1,350	-	2,700	-
Net earnings attributable to common shareholders of APUC – Basic and Diluted	$ (19,441)	$ 6,068	$ (1,581)	$ 8,342
Weighted average number of shares				
Basic	204,908,701	153,414,269	202,802,877	146,998,173
Dilutive effect of share-based awards	1,160,065	548,315	1,112,381	513,925
Diluted	206,068,766	153,962,584	203,915,258	147,512,098

For the three and six months ended June 30, 2013, the shares potentially issuable as a result of the convertible debentures as well as stock options of 816,402 and 816,407 (2012 – 1,696,486 and 1,704,785) are excluded from this calculation as they are anti-dilutive.

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

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 $6,000.

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 United States Environmental Protection Agency and the New Hampshire Department of Environmental Services ("NHDES"). Like most other industrial companies, the gas and electric distribution utilities generate some hazardous wastes. Under federal and state Superfund 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 System and Granite State Electric System 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 NHDES. 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.

As at June 30, 2013, the Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $62,876 (U.S. $59,780). At a discount rate of 3.5%, it represents a recorded accrual of $58,759 (December 31, 2012 - $56,857), the current portion of which amounts to $3,227. Remediation costs estimates

18. Commitments and contingencies (continued)

a) Contingencies (continued)

for each site may vary, depending upon changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered.

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, at June 30, 2013 the Company has reflected a regulatory asset of $62,310 (December 31, 2012 - $59,789) for the MGP and related sites.

Estimated cash flows for site investigation and remediation costs in the next five years and thereafter are as follows:

2013	$	1,019
2014		8,478
2015		25,060
2016		16,623
2017		1,053
Thereafter to 2047		10,643
	$	62,876

b) Commitments

In addition to the commitments relating to the proposed acquisitions disclosed in note 3 the following significant commitments exist as at June 30, 2013.

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 $16,900 over a period of five years related to compliance with the legislation.

APUC has outstanding purchase commitments for power purchases, gas delivery, service and supply, service agreements, capital project commitments and operating leases. Detailed below are estimates of future commitments under these arrangements:

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Purchased power	$ 58,115	$ 44,106	$ 20,443	$ -	$ -	$ -	$ 122,664
Gas delivery, service and supply agreements	26,554	18,128	10,443	5,945	5,272	52,903	119,245
Service agreements	25,809	21,587	27,707	28,042	29,169	504,246	636,560
Capital projects	20,242	500	-	-	-	-	20,742
Operating leases	5,280	5,023	4,086	3,546	3,350	88,712	109,997
Total	**$ 136,000**	**$ 89,344**	**$ 62,679**	**$ 37,533**	**$ 37,791**	**$ 645,861**	**$ 1,009,208**

Calpeco has entered into a five year all-purpose power purchase agreement ("PPA") with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2011 with a five year renewal option. The commitment amounts included in the table above are based on market prices as of June 30, 2013. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism. Granite State has several types of contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment.

Subsequent to quarter end on August 6, 2013, Liberty Utilities (Canada) Corp entered into an agreement to purchase a property located in Oakville, Ontario to host the Company's head office. The purchase, in an amount of $47,300 is expected to close on December 2, 2013. The company has already paid installments of $2,500.

19. Non-cash operating items

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

	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Accounts receivable	$ 240	$ (1,657)	$ (432)	$ (2,502)
Prepaid expenses	76	(217)	(120)	(227)
Accrued liabilities	157	9	71	(210)
	$ 473	$ (1,865)	$ (481)	$ (2,939)

19. Non-cash operating items (continued)

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

	Three months ended June 30,		Six months ended June 30,	
	2013	**2012**	**2013**	**2012**
Accounts receivable	$ 30,129	$ 1,570	$ (5,114)	$ 7,168
Related party balances	17	20	30	(65)
Natural gas inventory	(10,026)	-	(449)	-
Supplies and consumable inventory	(1,189)	(451)	(2,289)	(639)
Income tax receivable	(20)	(4)	(32)	(29)
Prepaid expenses	1,372	64	(1,742)	1,671
Accounts payable	(4,272)	(1,481)	(10,337)	427
Accrued liabilities	994	(1,098)	(17,071)	(9,368)
Current income tax liability	662	(120)	571	(137)
Net regulatory assets and liabilities	5,665	1,685	8,770	2,493
	$ 23,332	$ 185	$ (27,663)	$ 1,521

20. Segmented information

APUC has two operating segments: 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 electric, natural gas, water distribution or wastewater services.

Within APCo there are three divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops the Company's greenfield power generation projects as well as any expansion of the Company's existing portfolio of renewable energy and thermal energy facilities.

Liberty Utilities' operational segments are aggregated and reported by the following geographic territories: Liberty Utilities (West), Liberty Utilities (Central) and Liberty Utilities (East). Liberty Utilities (West) is comprised of Calpeco and the water distribution and wastewater utilities located in Arizona. Liberty Utilities (Central) is comprised of the Midwest Gas Utilities and the water distribution and wastewater utilities located in Texas, Missouri, Illinois and Arkansas. Liberty Utilities (East) is comprised of the New Hampshire and Georgia electric and gas utilities.

Operational segments

APUC's reportable segments are APCo - Renewable Energy, APCo - Thermal Energy, Liberty Utilities (West), Liberty Utilities (Central) and Liberty Utilities (East). 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 the loss on financial instruments to specific divisions. This allocation is determined when the initial foreign exchange forward contract is entered into. The unrealized portion of any gains or losses on derivatives instruments is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The interest rate swaps relate to specific debt facilities and gains and losses are allocated in the same manner as interest expense. Amounts relating to the convertible debentures are reported in the corporate segment.

The results of operations and assets for these segments are as follows:

20. Segmented information (continued)

Operational segments (continued)

	Three months ended June 30, 2013								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ -	$ -	$ -	$ -	$ 17,523	$ 18,830	$ 36,353	$ -	$ 36,353
Regulated gas sales and distribution	-	-	-	14,033	-	34,549	48,582		48,582
Regulated water reclamation and distribution	-	-	-	4,693	10,115	-	14,808	-	14,808
Non-regulated energy sales	36,980	9,564	46,544	-	-	-	-	-	46,544
Other revenue	1,986	474	2,460	-	3	-	3	-	2,463
Total revenue	38,966	10,038	49,004	18,726	27,641	53,379	99,746	-	148,750
Operating expenses	10,597	2,687	13,284	6,137	9,140	16,295	31,572	-	44,856
Regulated electricity purchased	-	-	-	-	8,238	12,720	20,958	-	20,958
Regulated gas purchased	-	-	-	7,023	-	17,867	24,890	-	24,890
Non-regulated fuel for generation	-	3,998	3,998	-	-	-	-	-	3,998
	28,369	3,353	31,722	5,566	10,263	6,497	22,326	-	54,048
Depreciation of property, plant and equipment	(9,424)	(2,750)	(12,174)	(2,072)	(3,302)	(4,966)	(10,340)	-	(22,514)
Amortization of intangible assets	(663)	(213)	(876)	(19)	(166)	-	(185)	-	(1,061)
Administration expenses	(3,461)	(140)	(3,601)	(804)	(2,289)	(851)	(3,944)	197	(7,348)
Foreign exchange gain	-	-	-	-	-	-	-	835	835
Interest expense	(6,607)	(177)	(6,784)	(907)	(4,833)	(2,563)	(8,303)	2,198	(12,889)
Interest, dividend and other income	553	(482)	71	130	235	973	1,338	757	2,166
Acquisition related costs	(289)	-	(289)	(14)	-	(218)	(232)	-	(521)
Gain on derivative financial instruments	258	-	258	-			-	260	518
Earnings/(loss) from continuing operations before income taxes	8,736	(409)	8,327	1,880	(92)	(1,128)	660	4,247	13,234
Gain/(loss)from discontinued operations before income taxes	1,427	(49,483)	(48,056)	-	-	-	-	-	(48,056)
Earnings/(loss) before income taxes	$ 10,163	$ (49,892)	$ (39,729)	$ 1,880	$ (92)	$ (1,128)	$ 660	$ 4,247	$ (34,822)
Capital expenditures	7,871	98	7,969	6,415	2,239	22,103	30,756	652	39,377
Acquisition of operating entities	2,311	-	2,311	584	-	156,591	157,175	-	159,486

20. Segmented information (continued)

Operational segments (continued)

	Six months ended June 30, 2013								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ -	$ -	$ -	$ -	$ 38,579	$ 40,629	$ 79,208	$ -	$ 79,208
Regulated gas sales and distribution	-	-	-	45,202	-	93,469	138,671		138,671
Regulated water reclamation and distribution	-	-	-	8,304	18,570	-	26,874	-	26,874
Non-regulated energy sales	76,710	16,764	93,474	-	-	-	-	-	93,474
Other revenue	2,703	1,124	3,827	-	17	-	17	-	3,844
Total revenue	79,413	17,888	97,301	53,506	57,166	134,098	244,770	-	342,071
Operating expenses	21,870	5,248	27,118	12,736	18,324	29,725	60,785	-	87,903
Regulated electricity purchased	-	-	-	-	19,809	27,152	46,961	-	46,961
Regulated gas purchased	-	-	-	27,865	-	56,075	83,940	-	83,940
Non-regulated fuel for generation	-	9,022	9,022	-	-	-	-	-	9,022
	57,543	3,618	61,161	12,905	19,033	21,146	53,084	-	114,245
Depreciation of property, plant and equipment	(20,446)	(4,081)	(24,527)	(4,038)	(6,285)	(8,618)	(18,941)	-	(43,468)
Amortization of intangible assets	(1,326)	(422)	(1,748)	(40)	(312)	-	(352)	-	(2,100)
Administration expenses	(5,965)	(391)	(6,356)	(548)	(2,996)	(1,320)	(4,864)	(985)	(12,205)
Foreign exchange gain	-	-	-	-	-	-	-	1,318	1,318
Interest expense	(13,092)	(760)	(13,852)	(938)	(6,981)	(2,649)	(10,568)	(668)	(25,088)
Interest, dividend and other income	937	(238)	699	168	874	1,345	2,387	1,299	4,385
Acquisition related costs	(366)	-	(366)	(61)	-	(587)	(648)	-	(1,014)
Gain on derivative financial instruments	695	-	695	-			-	1,209	1,904
Earnings/(loss) from continuing operations before income taxes	17,980	(2,274)	15,706	7,448	3,333	9,317	20,098	2,173	37,977
Gain/(loss) from discontinued operations before income taxes	2,114	(51,617)	(49,503)	-	-	-	-	-	(49,503)
Earnings/(loss) before income taxes	$ 20,094	$ (53,891)	$ (33,797)	$ 7,448	$ 3,333	$ 9,317	$ 20,098	$ 2,173	$ (11,526)
Property, plant and equipment	$ 1,311,362	$ 87,102	$ 1,398,464	$ 204,757	$ 370,061	$ 543,669	$ 1,118,487	$ -	$ 2,516,951
Intangible assets	28,141	6,059	34,200	2,721	19,295	-	22,016	-	56,216
Assets held for sale	3,815	29,192	33,007	-	-	-	-	-	33,007
Total assets	1,431,599	112,059	1,543,658	263,911	492,183	705,268	1,461,362	196,768	3,201,788
Capital expenditures	11,957	278	12,235	13,510	3,669	25,665	42,843	707	55,785
Acquisition of operating entities	(1,698)	-	(1,698)	27,545	-	146,342	173,887	-	172,189

20. Segmented information (continued)

Operational segments (continued)

	Three months ended June 30, 2012								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ -	$ -	$ -	$ -	$ 15,913	$ -	$ 15,913	$ -	$ 15,913
Regulated water reclamation and distribution	-	-	-	2,322	9,739	-	12,061	-	12,061
Non-regulated energy sales	22,288	7,548	29,836	-	-	-	-	-	29,836
Other revenue	458	366	824	-	85	-	85	-	909
Total revenue	22,746	7,914	30,660	2,322	25,737	-	28,059	-	58,719
Operating expenses	7,530	2,628	10,158	1,404	8,292	-	9,696	-	19,854
Regulated electricity purchased	-	-	-	-	9,661	-	9,661	-	9,661
Non-regulated fuel for generation	-	3,009	3,009	-	-	-	-	-	3,009
	15,216	2,277	17,493	918	7,784	-	8,702	-	26,195
Depreciation of property, plant and equipment	(4,070)	(998)	(5,068)	(302)	(3,013)	-	(3,315)	-	(8,383)
Amortization of intangible assets	(663)	(203)	(866)	(18)	(154)	-	(172)	-	(1,038)
Administration expenses	(1,832)	(137)	(1,969)	183	(290)	-	(107)	(3,402)	(5,478)
Foreign exchange loss	-	-	-	-	-	-	-	863	863
Interest expense	(2,781)	(357)	(3,138)	(17)	(1,852)	-	(1,869)	(1,195)	(6,202)
Interest, dividend and other income	559	231	790	-	121	-	121	569	1,480
Acquisition related costs	(782)	-	(782)	-	(1,271)	-	(1,271)	-	(2,053)
Loss on derivative financial instruments	(590)	-	(590)	-	-	-	-	(104)	(694)
Earnings from continuing operations before income taxes	5,057	813	5,870	764	1,325	-	2,089	(3,269)	4,690
Loss from discontinued operations before income taxes	(391)	1,387	996	-	-	-	-	-	996
Earnings/(loss) before income taxes	$ 4,666	$ 2, 200	$ 6,866	$ 766	$ 1,325	$ -	$ 2,089	$ (3,269)	$ 5,686
Capital expenditures	$ 6,711	$ 8,021	$ 1 4,732	$ 1,099	$ 3,238	$ -	$ 4,337	$ 15	$ 19,084

20. Segmented information (continued)

Operational segments (continued)

	Six months ended June 30, 2012								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ -	$ -	$ -	$ -	$ 35,299	$ -	$ 35,299	$ -	$ 35,299
Regulated water reclamation and distribution	-	-	-	4,507	18,147	-	22,654	-	22,654
Non-regulated energy sales	43,776	13,806	57,582	-	-	-	-	-	57,582
Other revenue	771	467	1,238	-	85	-	85	-	1,323
Total revenue	44,547	14,273	58,820	4,507	53,531	-	58,038	-	116,858
Operating expenses	14,493	4,368	18,861	2,559	17,723	-	20,282	-	39,143
Regulated electricity purchased	-	-	-	-	21,444	-	21,444	-	21,444
Non-regulated fuel for generation	-	7,041	7,041	-	-	-	-	-	7,041
	30,054	2,864	32,918	1,948	14,364	-	16,312	-	49,230
Depreciation of property, plant and equipment	(7,733)	(2,373)	(10,106)	(611)	(5,692)	-	(6,303)	-	(16,409)
Amortization of intangible assets	(1,326)	(405)	(1,731)	(38)	(308)	-	(346)	-	(2,077)
Administration expenses	(3,236)	(621)	(3,857)	(282)	(1,114)	-	(1,396)	(4,606)	(9,859)
Foreign exchange loss	-	-	-	-	-	-	-	409	409
Interest expense	(7,188)	(960)	(8,148)	(33)	(3,707)	-	(3,740)	(2,984)	(14,872)
Interest, dividend and other income	997	520	1,517	-	827	-	827	1,252	3,596
Acquisition related costs	(2,282)	-	(2,282)	-	(2,149)	-	(2,149)	-	(4,431)
Loss on derivative financial instruments	(1,669)	-	(1,669)	-	-	-	-	1,038	(631)
Earnings from continuing operations before income taxes	7,617	(975)	6,642	984	2,221	-	3,205	(4,891)	4,956
Loss from discontinued operations before income taxes	(711)	2,050	1,339	-	-	-	-	-	1,339
Earnings/(loss) before income taxes	$ 6,906	$ 1,075	$ 7,981	$ 984	$ 2,221	$ -	$ 3,205	$ (4,891)	$ 6,295
Capital expenditures	$ 9,570	$ 14,230	$ 23,800	$ 2,301	$ 4,589	$ -	$ 6,890	$ 38	$ 30,728
	December 31, 2012								
Property, plant and equipment	$ 1,157,062	$ 77,888	$ 1,234,950	$ 151,637	$ 350,053	$ 350,088	$ 851,778	$ -	$ 2,086,728
Intangible assets	29,480	6,132	35,612	2,613	18,556	-	21,169	-	56,781
Assets held for sale	24,390	78,497	102,887	-	-	-	-	-	102,887
Total assets	1,272,037	175,173	1,447,210	212,495	464,201	500,374	1,177,070	153,957	2,778,237

21. Financial instruments

(a) Fair value of financial instruments

	June 30, 2013				
	Carrying amount	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Notes receivable	$ 22,677	$ 24,835	$ -	$ -	$ 24,835
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	25,593	25,593	-	25,593	-
Cross-currency swap designated as a foreign exchange hedge	187	187	-	187	-
Commodity contracts for regulatory operations	14	14	-	14	-
Total derivative financial instruments	25,794	25,794	-	25,794	-
Total financial assets	$48,471	$50,629	$ -	$25,794	$24,835
Long-term liabilities	$ 1,091,452	$ 1,110,469	$ 295,143	$ 815,326	$ -
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	9,128	9,128	-	9,128	-
Cross-currency swap designated as a foreign exchange hedge	6,727	6,727	-	6,727	-
Interest rate swaps not designated as a hedge	3,735	3,735	-	3,735	-
Commodity contracts for regulated operations	1,147	1,147	-	1,147	-
Energy derivative contracts not designated as a hedge	129	129	-	129	-
Total derivative financial instruments	20,866	20,866	-	20,866	-
Total financial liabilities	$ 1,112,318	$ 1,131,335	$ 295,143	$ 836,192	$ -

	December 31, 2012				
	Carrying amount	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Notes receivable	$ 22,757	$ 25,476	$ -	$ -	$ 25,476
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	12,695	12,695	-	12,695	-
Cross-currency swap designated as a foreign exchange hedge	408	408	-	408	-
Commodity contracts for regulatory operations	147	147	-	147	-
Total derivative financial instruments	13,250	13,250	-	13,250	-
Total financial assets	$ 36,007	$ 38,726	$ -	$ 13,250	$ 25,476
Long-term liabilities	$ 770,826	$ 785,473	$ 293,348	$ 492,125	$ -
Convertible debentures	960	1,319	1,319	-	-
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	9,012	9,012	-	9,012	-
Cross-currency swap designated as a foreign exchange hedge	2,078	2,078	-	2,078	-
Interest rate swaps not designated as a hedge	4,778	4,778	-	4,778	-
Energy derivative contracts	287	287	-	287	-
Commodity contracts for regulated operations	1,661	1,661	-	1,661	-
Total derivative financial instruments	17,816	17,816	-	17,816	-
Total financial liabilities	$ 789,602	$ 804,608	$ 294,667	$ 509,941	$ -

21. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principle or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value (a level 2 measurement) at June 30, 2013 and December 31, 2012 due to the short-term maturity of these instruments.

The fair value of notes receivable 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. Such estimates are significantly influenced by unobservable data and therefore the fair value of notes receivable is subject to estimation risk.

APUC has long-term liabilities at both fixed interest rates and variable interest rates. The estimated fair value of such liabilities is calculated using current interest rates. The fair value of convertible debentures is determined using quoted market prices.

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 determined by applying an income approach using an option pricing model that incorporates 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 three months ended June 30, 2013 or 2012.

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the three or six months ended June 30, 2013 or 2012.

(b) Derivative instruments

Derivative instruments are recognized on the balance sheet 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 transactions associated with its regulated gas service territories.

The following are commodity volumes, in MMBTU associated with the above derivative contracts:

	2013
Financial contracts: Gas swaps	2,963,000
Gas options	1,989,200
	4,952,200

The change in fair value of the Company's derivative instruments is recorded as an offsetting adjustment to the regulatory assets and liabilities. As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no impact on net earnings.

(ii) Cash flow hedges

APCo reduces the price risk on the expected future sales of power generation from Sandy Ridge, Senate and Minonk and at one of its hydro facilities no longer subject to a PPA by entering into the following long-term energy derivative contracts.

21. Financial instruments (continued)

(b) Derivative instruments (continued)

Notional quantity as at June 30, 2013 (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Pay floating price (per MW-hr)
174,830	December 2016	$66.91	AESO
1,079,427	December 2022	U.S. $42.81	PJM Western HUB
4,614,671	December 2022	U.S. $30.25	NI HUB
4,801,636	December 2027	U.S. $36.46	ERCORT North HUB

The Company expects $6,153 of unrealized gains currently in accumulated other comprehensive loss to be reclassified into net earnings within the next twelve months, as the underlying hedged transactions settle.

(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.

Concurrent with its $150,000 debentures offering in December 2012, APCo entered into a cross currency swap, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into United States dollar ("USD"). 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, an economic 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. A foreign currency loss of $4,592 was recorded in other comprehensive income in the six months ended June 30, 2013.

(iv) Other derivatives

APCo satisfies the energy demands of various customers under fixed rate contracts. 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 contact term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

Notional quantity as at June 30, 2013 (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Net Asset
63,423	February 2014	U.S. $53.01	$(147)
26,304	March 2015	U.S. $47.88	(12)
92,870	March 2015	U.S. $47.88	30

For derivatives that are not designated as cash flow hedges and for the ineffective portion of gains and losses on derivatives that are accounted for as hedges, the changes in the fair value are immediately recognized in earnings. The effect on the unaudited interim consolidated statement of operations of derivative financial instruments not designated as hedges is as follows:

	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Change in unrealized loss/(gain) on derivative financial instruments:				
Interest rate swaps	$ (759)	$ 66	$ (1,043)	$ (1,116)
Energy derivative contracts	499	225	(166)	286
Total change in unrealized loss/(gain) on derivative financial instruments	$ (260)	$ 291	$ (1,209)	$ (830)
Realized loss/(gain) on derivative financial instruments:				
Foreign exchange contracts	$ -	$ (187)	$ -	$ (207)
Interest rate swaps	512	524	998	1,051
Energy derivative contracts	15	66	(723)	617
Total realized loss on derivative financial instruments	$ 527	$ 403	$ 275	$ 1,461
Loss/(gain) on derivative financial instruments accounted for as hedges	$ 267	$ 694	$ (934)	$ 631
Ineffective portion of derivatives financial instruments accounted for as hedges	(785)	-	(970)	-
Loss/(gain) on derivative financial instruments	$ (518)	$ 694	$ (1,904)	$ 631

21. 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 natural hedges by using U.S. long term debt to finance its U.S. operations.

In August 2012, APCo designated the amounts drawn on its U.S. dollar denominated bank credit facility as a hedge of the foreign currency exposure from net investment in 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 as a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in other comprehensive income) related to the net investment, to the extent it is effective as a hedge. A foreign currency loss of $1,809 was recorded in other comprehensive income in the six months ended June 30, 2013.

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 $63,236 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. At June 30, 2013, the estimated fair value of the interest rate swap was a liability of $3,735 (2012 – liability of $5,859). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

22. Non-controlling interests

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

	Three months ended June 30,		**Six months ended June 30,**	
	2013	**2012**	**2013**	**2012**
Net earnings/(loss) attributable to non-controlling interest	$ 4,039	$ -	$ 7,107	$ -
Hypothetical liquidation at book value (income) / loss	(7,532)	-	(12,564)	-
Other	39	402	39	993
Total	($3,454)	$ 402	($5,418)	$ 993

23. Comparative figures

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

Notes

Notes

Notes

Directors
Kenneth Moore, Chairman – Managing Partner, NewPoint Capital Partners Inc.
Christopher Ball – Executive Vice President, Corpfinance International Limited
Christopher Huskilson – President and Chief Executive Officer, Emera Inc.
Christopher Jarratt – Vice Chair, Algonquin Power & Utilities Corp.
Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.
George Steeves – Principal, True North Energy

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