

2010

Q3

Management's Discussion and Analysis

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

Management of Algonquin Power & Utilities Corp. ("APUC"), the corporation continuing the business of Algonquin Power Co. ("Algonquin"), formerly Algonquin Power Income Fund, has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and nine months ended September 30, 2010. This Management's Discussion and Analysis ("MD&A") should be read in conjunction with APUC's unaudited consolidated interim financial statements for the three and nine months ended September 30, 2010 and 2009 and the notes thereto as well as APUC's audited consolidated financial statements and APUC's MD&A for the year ended December 31, 2009. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of November 9, 2010.

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, which apply only as of their dates. APUC reviews material forward-looking information it has presented, at a minimum, 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" and "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA") are used throughout this MD&A. The terms "adjusted net

earnings” and Adjusted EBITDA are not recognized measures under Canadian generally accepted accounting principles (“GAAP”). There is no standardized measure of “adjusted net earnings” and Adjusted EBITDA, 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” and Adjusted EBITDA can be found throughout this MD&A.

Overview

APUC is a corporation incorporated under the Canada Business Corporations Act. APUC owns and operates a diversified portfolio of renewable energy and utility businesses through its subsidiary entities. APUC currently conducts its business primarily through two businesses.

Algonquin Power Co. (“APCo”) generates and sells electrical energy through a diverse portfolio of clean, renewable power generation and thermal power generation facilities across North America. As at September 30, 2010, APCo owns or has interests in 47 hydroelectric facilities operating in Ontario, Québec, Newfoundland, Alberta, New Brunswick, New York State, New Hampshire, Vermont, Maine and New Jersey with a combined generating capacity of 165 MW. APCo also owns a 99 MW wind powered generating station in Manitoba and an option to acquire an interest in a 26 MW wind powered generating station currently under construction in Saskatchewan. The renewable energy facilities generally sell their electrical output pursuant to long term power purchase agreements (“PPAs”) with major utilities and have an average remaining contract life of 16 years. Similarly, APCo’s ownership and interest in 14 thermal energy facilities operate under PPAs and have an average remaining contract life of 7 years with a combined generating capacity of 226 MW. During the third quarter, APCo determined that generating capacity should represent APCo’s percentage ownership interest in the facility, rather than the actual capacity of the facility. As a result, the generating capacity values disclosed have been reduced from prior periods.

Liberty Water Co. (“Liberty Water”) provides water and wastewater utility services through 19 water distribution and wastewater collection and treatment utility systems in the United States. Liberty Water provides regulated water distribution and wastewater facilities in Arizona, Illinois, Missouri and Texas. These utility operating companies are generally investor-owned utilities subject to regulation, including rate regulation, by the public utility commissions of the states in which they operate.

Liberty Energy Utilities Co. (“Liberty Energy”) has been formed to provide regulated local electrical distribution utility services. Through a strategic partnership with Emera Inc. (“Emera”), APUC announced plans to co-acquire the California-based electricity distribution and related generation assets of NV Energy, Inc, serving approximately 47,000 customers in the Lake Tahoe region (the “California Utility”). The transaction is subject to U.S. state and federal regulatory approval and is expected to close in late 2010 or early 2011 following receipt of all U.S. state and federal regulatory approvals. APUC owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the assets, California Pacific Electric Company (“Calpeco”). As

an element of the strategic partnership announced on April 23, 2009, Emera has also agreed to a conditional treasury subscription of approximately 8.5 million shares of APUC at a price of \$3.25 per share. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of the California Utility. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost of acquisition of the California Utility.

Business Strategy

APUC's business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation actively competing within the power and utilities business sectors. APUC is committed to delivering a total shareholder return comprised of a dividend augmented by capital appreciation arising through growth in earnings and dividends. Through an emphasis on sustainable, long view renewable power and utility investments, over a medium term planning horizon APUC strives to deliver annualized per share earnings growth of 5% and to grow its dividend supported by such earnings. APUC understands the importance of the dividend to its shareholders. APUC currently pays quarterly cash dividends to shareholders of \$0.06 per share or \$0.24 per share per annum. This level of dividends allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities, reduce short term debt obligations and mitigate the impact of volatility in foreign exchange rates. APUC strives to achieve its results within a moderate risk profile consistent with top-quartile North American power and utility operations.

Independent Power: APCo develops and operates a diversified portfolio of electrical energy generation facilities. Within this business there are three distinct divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates APCo's hydroelectric and wind power facilities. The Thermal Energy division operates co-generation, energy-from-waste, steam production and other thermal facilities. The Development division seeks to deliver continuing growth to APCo through development of APCo's greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of organic growth opportunities within APCo's existing portfolio of renewable energy and thermal energy facilities.

Regulated Utilities: Through its wholly owned subsidiary, Liberty Energy, APUC is pursuing further investment in electric and natural gas distribution utilities and electric transmission facilities, sharing certain common infrastructure between utilities to generate economies of scale to support best-in-class customer care for its subsidiary utility ratepayers.

Through its wholly owned subsidiary, Liberty Water, APUC is committed to being a leading utility provider of safe, high quality and reliable water and wastewater services while providing stable and predictable earnings from its utility operations. In addition to encouraging and supporting organic growth within its service territories, Liberty Water is focused on delivering continued growth in earnings by identifying opportunities which accretively expand its business portfolio.

Recent Developments

Red Lily Wind Project

On April 21, 2010, APUC announced that it had entered into agreements to provide development, construction, operation and supervision services related to the construction, commissioning and operation of a 26.4 megawatt wind energy facility (“Red Lily I”) in south-eastern Saskatchewan. The equity in Red Lily I (the “Partnership”) is owned by an independent investor, Concord Pacific Group. The facility will be financed by \$17.5 million of senior and subordinated debt from APUC, senior debt from third party lenders of \$31.0 million and an equity contribution from the independent investor of \$19.0 million.

APUC will provide services to and will receive fees for the development, construction, operation and supervision of the project. In addition, APUC has been granted an option to subscribe for a 75% equity interest in the project in exchange for its subordinated debt commitment, exercisable five years following commissioning of the project. *See Development Division – Red Lily I* for more discussion of this project.

Corporate Governance – Expanded Board of Directors

At the Meeting shareholders approved the re-election of existing Directors. In addition, Mr. Robertson and Mr. Jarratt were elected as Directors and joined the Board of Directors of APUC (the “Board”).

2010 Nine Month results from operations

Key Selected Nine Month Financial Information

	Nine months ended September 30	
	2010	2009
Revenue	\$ 134,008	\$ 143,824
Adjusted EBITDA ²	\$ 54,414	\$ 61,341
Cash provided by Operating Activities	28,065	37,473
Net earnings	2,751	32,623
Adjusted net earnings ³	3,728	18,999
Dividend/distributions to Shareholders/Unitholders ¹	17,040	14,324
Per share/trust unit		
Net earnings	\$ 0.03	\$ 0.42
Adjusted net earnings ³	\$ 0.04	\$ 0.24
Diluted net earnings	\$ 0.03	\$ 0.42
Cash provided by Operating Activities	\$ 0.30	\$ 0.47
Dividends/distributions to Shareholders/Unitholders	\$ 0.18	\$ 0.18
Total Assets	969,429	925,702
Long Term Debt ⁴	252,986	278,025

- 1 Includes dividends/distributions to APUC shareholders/unitholders and Airsource units exchangeable into APCo trust units.
- 2 APUC uses Adjusted EBITDA to enhance assessment and understanding of the operating performance of APUC without the effects of depreciation and amortization expense which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted EBITDA is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.
- 3 APUC uses Adjusted net earnings to enhance assessment and understanding of the performance of APUC without the effects of gains or losses on derivative financial instruments which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted net earnings is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.
- 4 Includes the revolving credit facility which matures on January 14, 2011 and has been recorded as a current liability on the consolidated balance sheet.

For the nine months ended September 30, 2010, APUC reported total revenue of \$134.0 million as compared to \$143.8 million during the same period in 2009, a decrease of \$9.8 million or 6.8%. The major factors resulting in the decrease in APUC revenue in the nine months ended September 30, 2010 as compared to the corresponding period in 2009, are set out as follows:

	Nine months ended September 30 2010
Comparative Prior Period Revenue	\$ 143,824
Significant Changes:	
Impact of the stronger Canadian dollar	(9,100)
Energy-from-Waste facility – impact of shutdown	(6,100)
Effect of hydrology compared to prior year averages	(5,200)
Windsor Locks - impact of change in operating model	(3,000)
Closure of land fill gas facilities	(1,200)
Effect of wind resource compared to prior year averages	(1,100)
Sanger – effect of hydro mulch demand offset by increased energy rates	(500)
Tinker/AES – acquisition in Q1 2010	13,500
Red Lily – development, construction supervision fees	1,600
Liberty Water completed rate cases	1,400
Other	(116)
Current Period Revenue	\$ 134,008

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

For the nine months ended September 30, 2010, APUC experienced an average U.S. exchange rate of approximately \$1.036 as compared to \$1.170 in the same period in 2009. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the nine months ended September 30, 2010 totalled \$54.4 million as compared to \$61.3 million during the same period in 2009, a decrease of \$6.9 million or 11.3%. The decrease in Adjusted EBITDA is in part due to lower earnings from operations primarily resulting from lower average hydrology and wind resources in the Renewable Energy division and the impact of the outage at the Energy-From-Waste ("EFW") facility, partially offset by the acquisition of the Tinker Assets as compared to the same period in 2009. A more detailed analysis of these factors is

presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the nine months ended September 30, 2010, net earnings totalled \$2.8 million as compared to \$32.6 million during the same period in 2009, a decrease of \$29.9 million or 91.6%. Net earnings per share totalled \$0.03 for the nine months ended September 30, 2010, as compared to net earnings per trust unit of \$0.42 during the same period in 2009.

Net earnings for the nine months ended September 30, 2010 decreased by \$4.6 million due to lower earnings from operating facilities, \$3.2 million due to increased interest expense, \$2.6 million related to lower recoveries of future income tax expense primarily due to the reasons discussed in *Corporate Expenses – Income Taxes*, \$1.4 million in reduced interest dividend and other income primarily due to gains on the sale of excess land earned in 2009, \$0.5 million due to non-cash losses on U.S. denominated liabilities resulting from the stronger Canadian dollar and \$0.9 million due to increased management and administration expense as compared to the same period in 2009. These items were partially offset by an increase of \$2.2 million resulting from reduced minority interest expense at the St. Leon facility primarily due to the lower wind resource experienced in the nine months ended September 30, 2010 as compared to the same period in 2009.

The decrease in net earnings was impacted by a change in unrealized mark-to-market losses on derivative financial instruments which reduced earnings by \$16.6 million in the nine months ended September 30, 2010 as compared to 2009, as a result of changes in the forward interest rate curve and the stronger Canadian dollar, in addition to an expense increase of \$2.2 million related to realized losses on derivative financial instruments contracts settled in the period.

The change in unrealized mark-to-market losses/(gains) on derivative financial instruments resulting from changes in foreign exchange rates relate to contract periods which extend to fiscal 2013. Unrealized mark-to-market losses on derivative financial instruments resulting from changes in interest rates relate to contract periods which extend to fiscal 2015. The following chart provides a summary of the period over period changes between realized and unrealized mark-to-market gains and losses of derivative financial instruments:

	Nine months ended		
	September 30		
	2010	2009	Change
Foreign Exchange Contracts:			
Change in unrealized mark-to-market gain on			
derivative financial instruments	\$ (727)	\$ (14,421)	\$ 13,694
Realized loss/(gain) on derivative financial instruments	(592)	431	(1,023)
	\$ (1,319)	\$ (13,990)	\$ 12,671

	Nine months ended September 30		
	2010	2009	Change
Interest Rate Swap Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	\$ (454)	\$ (5,797)	\$ 5,343
Realized loss on derivative financial instruments	4,635	3,984	651
	\$ 4,181	\$ (1,813)	\$ 5,994
Energy Forward Purchase Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	\$ (2,448)	-	\$ (2,448)
Realized loss on derivative financial instruments	2,531	-	2,531
	\$ 83	\$ -	\$ 83
Derivative Financial Instruments Total:			
Change in unrealized mark-to-market gain on derivative financial instruments	\$ (3,629)	\$ (20,218)	\$ 16,589
Realized loss on derivative financial instruments	6,574	4,415	2,159
Total loss/(gain) on derivative financial instruments	\$ 2,945	\$ (15,803)	\$ 18,748

During the nine months ended September 30, 2010, cash provided by operating activities totalled \$28.1 million or \$0.30 per share as compared to cash provided by operating activities of \$37.5 million, or \$0.47 per trust unit during the same period in 2009. Cash provided by operating activities exceeded dividends declared by 1.6 times during the nine months ended September 30, 2010 as compared to 2.6 times distributions during the same period in 2009. The change in cash provided by operating activities after changes in working capital in the nine months ended September 30, 2010, is primarily due to increased realized losses from derivative instruments and decreased cash flow from operating facilities as compared to the same period in 2009.

2010 Third quarter results from operations

Key Selected Third Quarter Financial Information

	Three months ended September 30	
	2010	2009
Revenue	\$ 45,443	\$ 45,110
Adjusted EBITDA ²	\$ 17,766	\$ 20,276
Cash provided by Operating Activities	6,142	14,388

	Three months ended September 30	
	2010	2009
Net earnings	1,533	13,078
Adjusted net earnings ³	873	7,243
Dividend/distributions to Shareholders/Unitholders ¹	5,754	4,775
Per share/trust unit		
Net earnings	\$ 0.02	\$ 0.17
Adjusted net earnings ³	\$ 0.01	\$ 0.09
Diluted net earnings	\$ 0.02	\$ 0.17
Cash provided by Operating Activities	\$ 0.06	\$ 0.18
Dividends/distributions to Shareholders/Unitholders	\$ 0.06	\$ 0.06
Total Assets	969,429	925,702
Long Term Debt ⁴	252,986	278,025

1 Includes dividends/distributions to APUC shareholders/unitholders and Airsource units exchangeable into APCo trust units.

2 APUC uses Adjusted EBITDA to enhance assessment and understanding of the operating performance of APUC without the effects of depreciation and amortization expense which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted EBITDA is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

3 APUC uses Adjusted net earnings to enhance assessment and understanding of the performance of APUC without the effects of gains or losses on derivative financial instruments which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted net earnings is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

4 Includes the revolving credit facility which matures on January 14, 2011 and has been recorded as a current liability on the consolidated balance sheet.

For the three months ended September 30, 2010, APUC reported total revenue of \$45.4 million as compared to \$45.1 million during the same period in 2009, an increase of \$0.3 million or 0.7%. The major factors resulting in the increase in APUC revenue in the three months ended September 30, 2010 as compared to the corresponding period in 2009 are set out as follows:

	Three months ended September 30 2010
Comparative Prior Period Revenue	\$ 45,110
Significant Changes:	
Tinker/AES – acquisition in Q1 2010	3,500
Liberty Water completed rate cases	800
Red Lily – development, construction supervision fees	600
Effect of wind resource compared to prior year averages	200
Effect of hydrology compared to prior year averages	(3,000)

	Three months ended September 30 2010
Impact of the stronger Canadian dollar	(1,500)
Sanger – effect of hydro mulch demand offset by increased energy rates	(200)
Closure of land fill gas facilities	(300)
Other	233
Current Period Revenue	\$ 45,443

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

For the three months ended September 30, 2010, APUC experienced an average U.S. exchange rate of approximately \$1.039 as compared to \$1.097 in the same period in 2009. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the three months ended September 30, 2010 totalled \$17.8 million as compared to \$20.3 million during the same period in 2009, a decrease of \$2.5 million or 12.4%. The decrease in Adjusted EBITDA is in part due to lower earnings from operations primarily resulting from lower average hydrology in the Renewable Energy division and the impact of the stronger Canadian dollar, partially offset by the acquisition of the Tinker Assets and increased revenues from Liberty Water resulting from the completion of rate cases as compared to the same period in 2009. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended September 30, 2010, net earnings totalled \$1.5 million as compared to net earnings of \$13.1 million during the same period in 2009, a decrease of \$11.5 million or 88.3%. Net earnings per share totalled \$0.02 for the three months ended September 30, 2010, as compared to net earnings per trust unit of \$0.17 during the same period in 2009.

Net earnings for the three months ended September 30, 2010 decreased by \$0.6 million due to lower earnings from operating facilities, \$1.4 million due to increased interest expense, \$1.5 million in decreased interest, dividend and other income primarily due to gains on the sale of excess land earned in 2009, \$0.8 million related to decreased recoveries of future income tax expense primarily due to the reasons discussed in *Corporate Expenses – Income Taxes*, and \$0.4 million due to increased management and administration expense as compared to the same period in 2009. These items were partially offset by a decrease of \$0.2 million due to lower amortization expense, \$1.2 million due to non-cash gains on U.S. denominated liabilities resulting from the stronger Canadian dollar, and \$0.2 million resulting from reduced minority interest expense at the St. Leon facility primarily due to the lower wind resource experienced in the quarter as compared to the same period in 2009.

The decrease in net earnings was impacted by a change in unrealized mark-to-market losses on derivative financial instruments which reduced earnings by \$7.5 million in the three months ended

September 30, 2010 as compared to 2009, as a result of changes in the forward interest rate curve and the stronger Canadian dollar.

The change in unrealized mark-to-market losses/(gains) on derivative financial instruments resulting from changes in foreign exchange rates relate to contract periods which extend to fiscal 2013. Unrealized mark-to-market losses on derivative financial instruments resulting from changes in interest rates relate to contract periods which extend to fiscal 2015. The following chart provides a summary of the period over period changes between realized and unrealized mark-to-market gains and losses of derivative financial instruments:

	Three months ended September 30		
	2010	2009	Change
Foreign Exchange Contracts:			
Change in unrealized mark-to-market loss/(gain) on derivative financial instruments	\$ (870)	\$ (7,696)	\$ 6,826
Realized gain on derivative financial instruments	(167)	(77)	(90)
	\$ (1,037)	\$ 7,773	\$ 6,736
Interest Rate Swap Contracts:			
Change in unrealized mark-to-market loss/(gain) on derivative financial instruments	\$ 345	\$ (849)	\$ 1,194
Realized loss on derivative financial instruments	1,453	1,522	(69)
	\$ 1,798	\$ 673	\$ 1,125
Energy Forward Purchase Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	\$ (534)	-	\$ (534)
Realized loss on derivative financial instruments	578	-	578
	\$ 44	\$ -	\$ 44
Derivative Financial Instruments Total:			
Change in unrealized mark-to-market gain on derivative financial instruments	\$ (1,059)	\$ (8,545)	\$ 7,486
Realized loss on derivative financial instruments	1,864	1,445	\$ 419
Total loss/(gain) on derivative financial instruments	\$ 805	\$ (7,100)	\$ 7,905

During the three months ended September 30, 2010, cash provided by operating activities totalled \$6.1 million or \$0.06 per share as compared to cash provided by operating activities of \$14.4 million, or \$0.18 per trust unit during the same period in 2009. Cash provided by operating activities exceeded dividends declared by 1.1 times during the quarter ended September 30, 2010 as compared to 3.0 times distributions during the same period in 2009. The change in cash provided by operating activities after changes in working capital in the three months ended September 30, 2010, is primarily due to reduced cash from working capital, increased interest expense and decreased interest, dividend and other income as compared to the same period in 2009.

Outlook

APCo

The APCo Renewable Energy division is expected to perform at long-term average resource conditions in the fourth quarter of 2010 based on the production results of October 2010. The wind resource at the St. Leon facility returned to long term averages during the third quarter of 2010 and is expected to remain at long term averages in the fourth quarter based on the production results of October 2010.

APCo's load supply and energy procurement contracts in northern Maine and the Independent System Operator New England ("ISO NE") market (the "Energy Services Business") anticipates that it will provide approximately 34,000 MW-hrs of energy to its customers in the fourth quarter of 2010. APCo anticipates that the Tinker Assets will provide greater than 75% of the energy required to service the Energy Services Business' customers and provide a natural hedge on supply costs of the Energy Services Business in the fourth quarter of 2010. In respect of each customer delivery obligation, the Energy Services Business has in place fixed price energy purchase contracts through the NE ISO to acquire the expected balance of energy needed to satisfy such obligation; such purchase contracts include additional volumes to address the potential of reasonable shortfalls in production from the Tinker Assets (including hydrology related) over the term of the energy delivery obligations to each customer.

Based on the operating results of EFW since July 2010, APCo does not anticipate that the temporary shut down of the EFW facility will negatively impact earnings in 2010, as compared to the previous year. APCo Thermal Energy division's EFW facility returned to full production on its five units on July 14, 2010. The facility has completed a major capital upgrade totaling \$10.4 million which included new boiler tubes on all units as well as several other operational improvements. The capital upgrade resulted in higher throughput and lower operating costs at EFW which positively affected operating profit by \$1.0 million in the third quarter of 2010, partially offsetting the negative impact to operating profits in the first two quarters of 2010. APCo now expects the facility to positively impact the operating profit in the fourth quarter of 2010 by \$0.9 million, resulting in the temporary shut down of the EFW facility having a minimal impact to operating profit in 2010, as compared to the same period in the prior year.

APCo Thermal Energy division's Sanger facility is expected to operate at or above APCo's expectations for the fourth quarter of 2010 in line with 2009 results. Hydro-mulch sales are expected to remain below expectations for the remainder of the year due to the economic conditions in the U.S. but the lower sales are expected to be offset by higher revenues from the power plant. APCo will continue to focus on cost containment and productivity improvement measures that will maximize Sanger's margins and EBITDA throughout 2010.

APCo Thermal Energy division's Windsor Locks facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity (up to a maximum of 40MW) available to be sold into the ISO NE day-ahead market. For

the period from October 1 through April 30, the facility did not to commit any portion of such remaining available capacity to the winter 2010/2011 forward reserve market ("FRM"). With the FRM clearing price of approximately \$6,800 per MW-month, APCo believes that superior economic performance will be achieved by committing the balance of all electrical capacity to the NE ISO day ahead market. Under the NE ISO rules, electrical producers are precluded from bidding any of the FRM committed electrical capacity at day ahead power prices at an implied heat rate of less than a 14,000 Btu/kWh. The Windsor Locks facility is capable of economically generating power for export in the 8,000 Btu/kWh to 9,000 Btu/kWh range and thus will be in a position to dispatch more by not being in the FRM market.

Following recent integrated resource planning hearings, the Connecticut Department of Public Utility Control ("DPUC") issued an order urging Connecticut Light and Power ("CL&P") to open negotiations to re-contract existing merchant generating facilities within Connecticut such as the Windsor Locks facility as an alternative to satisfy the requirement for additional generating capacity in the state. APCo representatives are pursuing such negotiations with CL&P as potential alternative operating regime to participation in the merchant NE ISO market.

The selected merchant operating regime is expected to negatively impact operating profit in the fourth quarter of 2010 by approximately U.S. \$1.2 million compared to the same period a year ago. For a more detailed description of the options and expected impact see *Development Division - Windsor Locks*.

Liberty Water

Liberty Water is expecting modest year over year growth in customers in the remainder of fiscal 2010. Liberty Water provides water distribution and wastewater collection and treatment services, primarily in the southern and southwestern U.S. where communities have traditionally experienced long term growth and provide continuing future opportunities for organic growth.

On October 5, 2010, Liberty Water received a Recommended Order & Opinion ("ROO") from the Administrative Law Judge with respect the rate case at its Litchfield Park utility ("LPSCo") which recommends a revenue requirement of \$8.1 million. This ROO is subject to final approval of the Commissioners of Arizona Corporate Commission ("ACC"). Including the recommended revenue requirement from the LPSCo ROO, revenue increases from rate cases completed in Arizona and Texas are expected to contribute an additional \$10.4 million in annualized run rate revenue. A final order from the ACC regarding the LPSCo rate case is expected in the fourth quarter with the new rates going into effect immediately thereafter.

Liberty Energy

In 2009, APUC announced plans to co-acquire an electrical generation and regulated distribution utility through a strategic partnership with Emera. The utility is the California-based electricity distribution and related generation assets of NV Energy, Inc. Liberty Energy is pursuing additional investments in electric distribution utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best in-class-customer care for its subsidiary utility ratepayers.

The acquisition is proceeding through the regulatory approval process before the California Public Utilities Commission ("CPUC"). On September 14, 2010, Calpeco received a favourable conditional decision from an Administrative Law Judge ("ALJ") of CPUC related to its regulatory proceedings on the purchase of the California electricity distribution and related generation assets of NV Energy. On October 15, 2010, the CPUC approved the ALJ's decision. The period in which this decision can be appealed lapses after November 15, 2010. The CPUC's decision is consistent with Calpeco's filings and testimony and did not contain a rate freeze provision. The transaction is also subject to the pending approval of the Public Utilities Commission of Nevada expected in mid-December 2010. Closing is expected in late 2010 or early 2011, as compared to the previously expected time of late 2010. The change is due to the timing of the regulatory approval process.

APCo: Renewable Energy

	Three months ended September 30			Nine months ended September 30		
	Long Term Average Resource	2010	2009	Long Term Average Resource	2010	2009
Performance (MW-hrs sold)						
Quebec Region	63,775	50,225	71,675	204,250	191,725	226,250
Ontario Region	31,925	17,300	31,500	109,975	70,025	104,450
Manitoba Region	76,000	80,875	76,600	267,000	245,950	274,875
New England Region	8,300	2,545	19,850	49,850	34,520	65,525
New York Region	11,850	11,225	17,300	67,000	55,175	70,250
Western Region	25,000	25,700	22,200	53,850	48,650	47,325
Maritime Region	21,375	19,525	1,375	108,675	93,025	4,600
Total	238,225	207,395	240,500	860,600	739,070	793,275
Revenue						
Energy sales		\$ 16,057	\$ 15,198	\$ 58,250	\$ 51,623	
Less:						
Cost of Sales – Energy*		(1,656)	-	(4,616)	-	
Net Energy Sales		\$ 14,401	\$ 15,198	\$ 53,634	\$ 51,623	
Other Revenue		562	-	1,559	-	
Total Net Revenue		\$ 14,963	\$ 15,198	\$ 55,193	\$ 51,623	
Expenses						
Operating expenses		(6,207)	(4,932)	(17,421)	(15,660)	
Interest and Other income		230	241	632	793	
Division operating profit (including other income)		\$ 8,986	\$ 10,507	\$ 38,404	\$ 36,756	

* Cost of Sales – Energy consists of energy purchases by the Energy Services Business, where this energy is immediately sold to customers pursuant to fixed rate energy contracts.

As APCo's hydroelectric generating facilities in the New York and New England regions primarily sell their output at market rates, the average revenue earned per MW-hr sold can vary significantly from the same period in the prior period or year. APCo's hydroelectric generating facilities in the Maritime

region primarily sell their output to the Energy Services Business which sells this energy at fixed price contracts to local electric utilities and commercial buyers in Northern Maine. APCo's facilities in the other regions are subject to varying rates, by facility, as set out in each facility's individual PPA. As such, 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.

2010 Nine Month Operating Results

For the nine months ended September 30, 2010 the Renewable Energy division produced 739,070 MW-hrs of electricity, as compared to 793,275 MW-hrs produced in the same period in 2009, a decrease of 6.8%. The level of production in 2010 represents sufficient renewable energy to supply the equivalent of 55,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 400,000 tons of CO₂ gas was prevented from entering the atmosphere in the three quarters of 2010.

During the nine months ended September 30, 2010, the division generated electricity equal to 86% of long-term projected average resources (wind and hydrology) as compared to 106% during the same period in 2009. In the first nine months of 2010, all regions experienced resources below long-term averages. The Quebec, Western and Manitoba regions experienced resources within 10% of long-term averages. Four regions experienced results significantly below long-term averages including the Ontario and New England regions, which were approximately 35% below long-term average resources, and the New York and Maritimes regions which were approximately 15% below long-term averages. The lower wind resource in the Manitoba region in the first quarter of 2010 was similar to lower wind resources experienced at other wind farms in North America in the first quarter of 2010, but returned to the long-term expected average in the second and third quarters of 2010.

For the nine months ended September 30, 2010, revenue from energy sales in the Renewable Energy division totalled \$58.3 million, as compared to \$51.6 million during the same period in 2009, an increase of \$6.6 million or 12.8%. 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 nine months ended September 30, 2010, net revenue from energy sales in the Renewable Energy division totalled \$53.6 million, as compared to \$51.6 million during the same period in 2009, an increase of \$2.0 million or 3.9%.

Revenue from APCo's New England and New York region facilities increased \$0.5 million due to an increase in weighted average energy rates of approximately 15.6% and decreased \$2.1 million due to decreased average hydrology, as compared to the same period in 2009. Revenue from the Manitoba region increased \$1.0 million due to an increase in weighted average energy rates of approximately 7.3%, offset by a decrease of \$2.1 million due to a weaker wind resource, as compared to the same period in 2009. The Manitoba Region PPA requires the facility to generate a minimum amount of

dependable energy during the contract year ending April 30. Energy generated above the dependable amount earns revenue at lower, non-dependable rates. As a result of the lower production experienced in the first quarter of 2010, during the contract year ending April 30, 2010, the facility earned revenue primarily at the dependable rates as compared to the same period in 2009 where a greater proportion of revenue was earned at the non-dependable rates. Revenue generated by the Ontario, Quebec and Western regions increased by \$1.1 million due to an increase in weighted average energy rates of approximately 4.8%, primarily the result of increased rates at the Long Sault facility in the Ontario region, as compared to the same period in 2009. The increases in revenue at APCo's Ontario, Quebec and Western regions were offset by a decrease of \$4.8 million due to lower energy production, primarily the result of lower production at the Long Sault facility in the Ontario region, as compared to the same period in 2009. The Maritime region, in conjunction with the Energy Services Business, generated \$13.5 million in revenue, before energy purchases. This revenue consists of sales to local electric utilities and wholesale consumers in Northern Maine of \$11.5 million, \$1.3 million to a town in New Brunswick and \$0.9 million representing merchant sales of production in excess of customer demand.

Other revenue for the nine months ended September 30, 2010 totalled \$1.6 million, as compared to nil during the same period in 2009. Other revenue represents amounts earned related to the development and construction of the Red Lily I wind project.

The division reported decreased revenue of \$0.5 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the nine months ended September 30, 2010, energy purchase costs by the Energy Services Business totalled U.S. \$4.5 million. During the first nine months of 2010, the Energy Services Business purchased approximately 72,400 MW-hrs of energy at market and fixed rates averaging U.S. \$61 per MW-hr. The Maritime region generated approximately 50% of the load required to service its customers as well as the Energy Services Business's customers in the nine months ended September 30, 2010. The energy purchases represent a combination of the load requirement of the Energy Services Business's customers and the timing of this demand as compared to the energy produced by the Tinker Assets and the timing of this production. The division reported increased energy costs of \$0.1 million as a result of the Canadian dollar exchange rates.

For the nine months ended September, 2010, operating expenses excluding energy purchases totalled \$17.4 million, as compared to \$15.7 million during the same period in 2009, an increase of \$1.8 million or 11.2%. Operating expenses were impacted by \$1.3 million of increased expenses at the St. Leon facility, primarily resulting from scheduled payments under the extended warranty and operation and maintenance agreement with Vestas, \$0.3 million of increased operating expenses at the U.S. hydroelectric facilities, and \$1.9 million related to operating costs associated with the Tinker Assets and the Energy Services Business as compared to the same period in 2009. These increases were partially offset by \$0.6 million in decreased operating costs at Canadian facilities, primarily due to lower variable operating costs tied to lower revenue and lower repair and maintenance projects

commenced in the nine months ended September 30, 2010. Operating expenses include costs incurred in the period of \$1.2 million associated with the pursuit of various growth and development activities, including operating expenses associated with the construction supervision work on the Red Lily I wind project, as compared to development costs incurred of \$1.2 million in the same period in 2009. Operating expenses were lower due to a reimbursement of \$0.9 million related to costs previously expensed by APUC in connection with the development of the Red Lily I wind project. The division reported decreased expenses of \$0.3 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the nine months ended September 30, 2010, Renewable Energy's operating profit totalled \$38.4 million, as compared to \$36.8 million during the same period of 2009, representing an increase of \$1.6 million or 4.5%. Renewable Energy's operating profit did not meet APCo's expectations primarily due to a lower than expected wind resource in the Manitoba region in the first quarter of 2010 and lower hydrology in the second and third quarters of 2010.

2010 Third Quarter Operating Results

For the quarter ended September 30, 2010, the Renewable Energy division produced 207,395 MW-hrs of electricity, as compared to 240,500 MW-hrs produced in the same period in 2009, a decrease of 13.8%. The level of production in 2010 represents sufficient renewable energy to supply the equivalent of 46,100 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 115,000 tons of CO₂ gas was prevented from entering the atmosphere in the third quarter of 2010.

During the quarter ended September 30, 2010, the division generated electricity equal to 87% of long-term projected average resources (wind and hydrology) as compared to 111% during the same period in 2009. In the third quarter of 2010, production in the Manitoba and Western regions were slightly above long-term average resources. The New York and the Maritimes regions experienced resources within 10% of long-term average resources. The Quebec region experienced resources of approximately 20% below long-term average resources. Several regions experienced results significantly below long-term averages, including the Ontario and New England regions.

For the quarter ended September 30, 2010, revenue from energy sales in the Renewable Energy division totalled \$16.1 million, as compared to \$15.2 million during the same period in 2009, an increase of \$0.9 million or 5.6%. 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 September 30, 2010, net revenue from energy sales in the Renewable Energy division totalled \$14.4 million, as compared to \$15.2 million during the same period in 2009, a decrease of \$0.8 million or 5.2%.

Revenue from APCo's New England and New York region facilities increased \$0.2 million due to an increase in weighted average energy rates of approximately 46.0%, offset by \$1.0 million due to decreased average hydrology, as compared to the same period in 2009. Revenue from the Manitoba

region increased \$0.2 million primarily due to a stronger wind resource, as compared to the same period in 2009. Revenue generated by the Ontario, Quebec and Western regions increased by \$0.1 million due to an increase in weighted average energy rates of approximately 2.0%, primarily the result of increased rates at the Long Sault facility in the Ontario region, as compared to the same period in 2009. The increases in revenue at APCo's Ontario, Quebec and Western regions were offset by a decrease of \$2.3 million due to lower energy production, primarily the result of lower production at the Long Sault facility in the Ontario region, as compared to the same period in 2009. The Maritime region, in conjunction with the Energy Services Business, generated \$3.5 million in revenue, before energy purchases. This revenue consists of sales to local electric utilities and wholesale consumers in Northern Maine of \$3.0 million, \$0.4 million to a town in New Brunswick and \$0.1 million representing merchant sales of production in excess of customer demand.

Other revenue for the three months ended September 30, 2010 totalled \$0.6 million, as compared to nil during the same period in 2009. Other revenue represents amounts earned related to the development and construction of the Red Lily I wind project.

For the quarter ended September 30, 2010, energy purchase costs by the Energy Services Business totalled U.S. \$1.6 million. During the quarter, the Energy Services Business purchased approximately 24,400 MW-hrs of energy at market and fixed rates averaging \$65 per MW-hr. The Maritime region generated approximately 60% of the load required to service its customers as well as the Energy Services Business' customers in the three months ended September 30, 2010. The energy purchases represent a combination of the load requirement of the Energy Services Business' customers and the timing of this demand as compared to the energy produced by the Tinker Assets and the timing of this production.

For the quarter ended September 30, 2010, operating expenses excluding energy purchases totalled \$6.2 million, as compared to \$4.9 million during the same period in 2009, an increase of \$1.3 million or 25.9%. Operating expenses were impacted by \$0.4 million of increased expenses at the St. Leon facility, primarily resulting from scheduled payments under the extended warranty and operation and maintenance agreement with Vestas and \$0.6 million related to operating costs associated with the Tinker Assets and the Energy Services Business, as compared to the same period in 2009. Operating expenses include costs incurred in the period of \$0.5 million associated with the pursuit of various growth and development activities, including operating expenses associated with the construction supervision work on the Red Lily I wind project as compared to development costs incurred of \$0.4 million in the same period in 2009. The division reported increased expenses of \$0.1 million from U.S. operations as a result of the increased U.S. dollar revenue as compared to the same period in 2009.

For the quarter ended September 30, 2010, Renewable Energy's operating profit totalled \$9.0 million, as compared to \$10.5 million during the same period of 2009, representing a decrease of \$1.5 million or 14.5%. For the quarter ended September 30, 2010, Renewable Energy's operating profit did not meet APCo's expectations primarily due to lower hydrology in the second and third quarters of 2010 at the Canadian facilities.

Divisional Outlook – Renewable Energy

The APCo Renewable Energy division is expected to perform at long-term average resource conditions for both hydrology and wind resources in the fourth quarter of 2010 based on the production results of October 2010.

Plans are underway to expand the Energy Services Business to include the marketing of the output of the New York and New England region hydroelectric generating facilities.

The Energy Services Business anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 34,000 MW-hrs of energy to its customers in the fourth quarter of 2010. The Energy Services Business operates on a 'balanced book' basis. Essentially, the Energy Services Business purchases sufficient energy on the ISO NE market to meet its actual customer load during those periods when the energy generated by the Tinker Assets is insufficient to meet the demand of these customers and subsequently sells the surplus energy generated by the Tinker Assets on the ISO NE market when the production exceeds the customer demand in the period. Based on historical long term average levels of hydroelectric energy generation over the remainder of 2010, the Tinker Assets are anticipated to provide greater than 75% of the energy required by the Energy Services Business to service its customers which provides a natural hedge on supply costs of the Energy Services Business. In respect of each customer delivery obligation, the Energy Services Business has in place fixed price energy purchase contracts through the NE ISO to acquire the expected balance of energy needed to satisfy such obligation; such purchase contracts include additional volumes to address the potential of reasonable shortfalls in production from the Tinker Assets (including hydrology related) over the term of the energy delivery obligations to each customer.

As a result of certain legislation passed in Quebec (Bill C93), APCo's Renewable Energy division is required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased within the Province of Quebec. As a result of the assessments and a preliminary evaluation of the associated remedial work, APCo currently estimates capital expenditures of approximately \$17.1 million related to compliance with the legislation. The timing of when the actual capital costs need to be made is determined as part of the technical assessments.

APCo anticipates that these expenditures will be invested over the next five years approximately as follows:

	Total	2010	2011	2012	2013	2014
Estimated Bill C-93						
Capital Expenditures	17,100	100	5,400	5,800	3,000	2,800

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Mont-Laurier facilities. During the third quarter, APCo reduced its estimates related to the Mont Laurier capital expenditures and currently anticipates the majority of the costs associated with the facility will be incurred in fiscal 2011. APCo has obtained both time and material and fixed price quotes in relation to the Donnacona facility and is currently investigating alternative engineering

designs that may reduce the overall estimated cost of the construction project. APCo does not anticipate any significant impact on power generation or associated revenue while the dam safety work is ongoing. APCo continues to explore several alternatives to mitigate the capital costs of the modifications, including cost sharing with other stakeholders and revenue enhancements which can be achieved through the modifications.

APCo: Thermal Energy Division

	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Performance (MW-hrs sold)	105,725	143,640	344,775	424,023
Performance (tonnes of waste processed)	40,620	41,914	47,170	118,913
Revenue				
Energy sales	\$ 14,354	\$ 14,941	\$ 40,424	\$ 48,390
Less:				
Cost of Sales – Fuel *	(5,317)	(5,521)	(16,856)	(21,293)
Net Energy Sales Revenue	\$ 9,037	\$ 9,420	\$ 23,568	\$ 27,097
Waste disposal sales	3,868	3,821	4,875	10,682
Other revenue	354	928	898	3,303
Total net revenue	\$ 13,259	\$ 14,169	\$ 29,341	\$ 41,082
Expenses				
Operating expenses *	(6,070)	(7,581)	(17,821)	(23,661)
Interest and other income	125	425	395	681
Division operating profit				
(including interest and dividend income)	\$ 7,314	\$ 7,013	\$ 11,915	\$ 18,102

* Cost of Sales – Fuel consists of natural gas and fuel costs at the Sanger and Windsor Locks facilities, where changes in these costs are passed to the customer in the energy price.

APCo's Sanger and Windsor Locks generation facilities purchase natural gas from different suppliers and in 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 showing decreasing costs, as compared to the same period in the prior year. 'Cost of Sales – Fuel' is calculated as the volume of natural gas consumed by a facility times the average landed cost of natural gas. As a result, a facility may record a higher aggregate expense for natural gas as a result of a lower average landed cost for natural gas combined with a consumption of a higher volume of natural gas.

2010 Nine Month Operating Results

In the first three quarters of 2010, the EFW facility processed 47,170 tonnes of municipal solid waste as compared to 118,913 tonnes processed in the same period of 2009, a decrease of 60.3%. The significantly reduced throughput was a result of the unplanned outage experienced in January 2010 which resulted in the facility being temporarily shut down. The major capital upgrades to the facility were completed at the end of the second quarter and the facility was restarted on July 14, 2010. The status of this facility is discussed in further detail in *Divisional Outlook – Thermal Energy*, below. This level of production resulted in the diversion of approximately 30,000 tonnes of waste from landfill sites in the first nine months of 2010.

During the nine months ended September 30, 2010, the business unit produced 344,775 MW-hrs of energy as compared to 424,028 MW-hrs of energy in the comparable period of 2009. During the nine months ended September 30, 2010, the business unit's performance decreased by 58,500 MW-hrs at the Windsor Locks facility, 17,400 MW-hrs at the land-fill gas ("LFG") facilities and 4,500 MW-hrs from EFW's steam turbine as compared to the same period in 2009. The decrease in electrical generation at the Windsor Locks facility was the expected result of the expiry of the PPA with CL&P in April 2010 and the change in operating model for the facility to one where revenues are earned from capacity payments from ISO NE and forward reserve market payments from the TMOR market. As a result, the facility will only generate additional energy when dispatched by ISO NE which will result in reduced energy production on a go-forward basis. The decrease in electrical generation at the EFW facility was the result of the unplanned outage which occurred in January 2010.

During the nine months ended September 30, 2010, APCo ceased generating energy at the LFG facilities and has initiated a process to close these facilities. The decreases in energy generation were partially offset by an increase of 1,000 MW-hrs at the Valley Power facility.

For the nine months ended September 30, 2010, revenue in the Thermal Energy division totalled \$46.2 million, as compared to \$62.4 million during the same period in 2009, a decrease of \$16.2 million or 25.9%. 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 a more appropriate measure of the division's results. For the nine months ended September 30, 2010, net energy sales revenue at the Thermal Energy division totalled \$23.6 million, as compared to \$27.1 million during the same period in 2009, a decrease of \$3.5 million or 13.0%. The decrease in revenue from energy sales was primarily due to a decrease of \$3.0 million at the Windsor Locks facility as a result of decreased energy rates, in part due to lower average landed price per mmbtu for natural gas and the change in operating model of the facility, partially offset by \$0.8 million at the Sanger facility as a result of increased energy rates, in part due to higher average landed price per mmbtu for natural gas and \$0.1 million as a result of increased production, as compared to the same period in 2009. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased revenue of \$4.9 million from operations as a result of the stronger Canadian dollar, as compared to the same period in 2009.

Revenue from waste disposal sales for the nine months ended September 30, 2010 totalled \$4.9 million, as compared to \$10.7 million during the same period in 2009. The EFW facility generated lower revenue in the period as it was temporarily shut down between January and July 2010 as a result of the unplanned outage.

Other revenue for the nine months ended September 30, 2010 totalled \$0.9 million, as compared to \$3.3 million during the same period in 2009. The decrease in other revenue was primarily due to a decrease of \$1.4 million at the hydro-mulch facility due to reduced customer demand. In the comparable period in 2009, other revenue included \$0.5 million from APCo's MGT facility which was not operational in the current period. The division reported decreased other revenue of \$0.4 million as a result of the stronger Canadian dollar, as compared to the same period in 2009.

For the nine months ended September 30, 2010, fuel costs at Sanger and Windsor Locks totalled U.S. \$16.3 million, as compared to U.S. \$18.0 million during the same period in 2009, a decrease of U.S. \$1.8 million. The overall natural gas expense at the Windsor Locks facility decreased \$2.3 million (16%), primarily the result of a 4% decrease in the average landed cost of natural gas per mmbtu combined with a 12% reduction in volume of natural gas consumed, as compared to the same period in 2009. The average landed cost of natural gas at the Windsor Locks facility was U.S. \$4.79 per mmbtu. This was partially offset by an increase in the overall natural gas expense at Sanger of \$0.6 million (19%), primarily the result of a 20% increase in the average landed cost of natural gas per mmbtu. The average landed cost of natural gas at the Sanger facility was U.S. \$4.94 per mmbtu. The division reported decreased fuel costs of \$2.7 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the nine months ended September 30, 2010, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled \$17.8 million, as compared to \$23.7 million during the same period in 2009, a decrease of \$5.9 million. The decrease in operating expenses for the quarter was primarily due to reduced operating costs of \$5.1 million at the EFW facility resulting from the outage at the facility, reduced material costs of \$0.7 million at the hydro-mulch facility resulting from lower production, and \$0.9 million of lower costs due to the closing of the LFG facilities partially offset by increased natural gas expense of \$1.4 million at the Brampton Co-generation Inc. ("BCI") facility as a result of decreased steam production at EFW and increased steam production from BCI's auxiliary boiler as compared to the same period in 2009. Operating expenses include costs of \$0.4 million associated with the pursuit of various growth and development activities, as compared to nil in the same period in 2009. The division reported decreased operating expenses of \$1.3 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

Interest and other income for the nine months ended September 30, 2010 totalled \$0.4 million, as compared to \$0.7 million in the same period in 2009. During the second quarter, APUC determined that earnings from equity investments should be presented at the corporate level rather than at a divisional level as APCo does not manage these investments. As a result, the comparable figures have been reclassified to conform to the presentation adopted in the current year.

For the nine months ended September 30, 2010, the Thermal Energy division's operating profit totalled \$11.9 million, as compared to \$18.1 million during the same period in 2009, representing a decrease of \$6.2 million or 34%. Operating profit in the Thermal Energy division did not meet overall expectations for the nine months ended September 30, 2010, primarily due to the unplanned outage at the EFW facility, the change in operating model at Windsor Locks and lower demand for hydro-mulch resulting from the current economic slow down in the U.S.

2010 Third Quarter Operating Results

During the quarter ended September 30, 2010, the business unit produced 105,725 MW-hrs of energy as compared to 143,640 MW-hrs of energy in the comparable period of 2009. During the quarter ended September 30, 2010, the business unit's performance decreased by 31,000 MW-hrs at the Windsor Locks facility and 6,900 MW-hrs at the LFG facilities as compared to the same period in 2009. See the discussion of the year to date operating results regarding the decrease in electrical generation at the Windsor Locks facility. The LFG facilities did not operate as APCo has initiated a process to close these facilities in the first quarter of 2010.

For the quarter ended September 30, 2010, revenue in the Thermal Energy division totalled \$18.6 million, as compared to \$19.7 million during the same period in 2009, a decrease of \$1.1 million, or 5.7%. 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 a more appropriate measure of the division's results. For the quarter ended September 30, 2010, net energy sales revenue at the Thermal Energy division totalled \$9.0 million, as compared to \$9.4 million during the same period in 2009, a decrease of \$0.4 million. The decrease in revenue from energy sales was primarily due to a decrease of \$0.3 million as a result of the closure of the LFG facilities, offset by \$0.2 million at the BCI facility as a result of increased price for steam, \$0.3 million at the Sanger facility as a result of increased energy rates, in part due to higher average landed price per mmbtu for natural gas prices and production volumes as compared to the same period in 2009. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased revenue of \$0.7 million from operations as a result of the stronger Canadian dollar, as compared to the same period in 2009.

Revenue from waste disposal sales for the quarter ended September 30, 2010 totalled \$3.9 million, as compared to \$3.8 million during the same period in 2009. The EFW facility resumed production in July 2010 and operated in line with managements expectations during the quarter.

Other revenue for the quarter ended September 30, 2010 totalled \$0.4 million, as compared to \$0.9 million during the same period in 2009. The decrease in other revenue was due to decreased revenue at the hydro-mulch facility due to reduced customer demand in the quarter.

For the quarter ended September 30, 2010, fuel costs at Sanger and Windsor Locks totalled U.S \$5.1 million, as compared with U.S \$5.0 million in the same period in 2009. The overall natural gas expense at the Windsor Locks facility decreased \$0.2 million (4%), primarily the result of a 21% reduction in volume of natural gas consumed, partially offset by a 23% increase in the average

landed cost of natural gas per mmbtu, as compared to the same period in 2009. The average landed cost of natural gas at the Windsor Locks facility during the quarter was U.S. \$4.99 per mmbtu. This was partially offset by an increase in the natural gas expense at Sanger of \$0.2 million (27%), primarily the result of a 27% increase in the average landed cost of natural gas per mmbtu as compared to the same period in 2009. The average landed cost of natural gas at the Sanger facility during the quarter was U.S. \$4.41 per mmbtu. The division reported decreased fuel costs of \$0.3 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the quarter ended September 30, 2010, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled \$6.1 million, as compared to \$7.6 million during the same period in 2009, a decrease of \$1.5 million. The decrease in operating expenses for the quarter was primarily due to reduced operating costs of \$0.9 million at the EFW facility as a result of increased operating efficiencies from the major capital upgrades completed at the facility, reduced material costs of \$0.2 million at the hydro-mulch facility resulting from lower production, and \$0.4 million of reduced operating costs at the LFG facilities partially offset by increased operating and repairs and maintenance expenses of \$0.2 million at the Valley Power facility and repairs and maintenance expense as compared to the same period in 2009. Operating expenses include costs of \$0.1 million associated with the pursuit of various growth and development activities, as compared to nil in the same period in 2009. The division reported decreased operating expenses of \$0.2 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

Interest and other income for the three months ended September 30, 2010 totalled \$0.1 million, as compared to \$0.4 million in the same period in 2009. During the second quarter, APUC determined that earnings from equity investments should be presented at the corporate level rather than at a divisional level as APCo does not manage these investments. As a result, the comparable figures have been reclassified to conform to the presentation adopted in the current year.

For the quarter ended September 30, 2010, the Thermal Energy division's operating profit totalled \$7.3 million, as compared to \$7.0 million during the same period in 2009, representing an increase of \$0.3 million or 4.3%. Operating profit in the Thermal Energy division met overall expectations for the quarter ended September 30, 2010, primarily due to the EFW facility generating better than expected results and higher than expected earnings at the Windsor Locks facility as a result of increased energy rates.

Divisional Outlook – Thermal Energy

Based on the operating results of EFW since July 2010, APCo does not anticipate that operating profit from EFW will negatively impact earnings in 2010, as compared to the previous year. APCo Thermal Energy division's EFW facility returned to full production on its five units on July 14, 2010. The facility is expected to operate above APCo's expectations for the remainder of the year processing approximately 500 tonnes of waste each day. The facility has completed a major capital upgrade totaling \$10.4 million which included new boiler tubes on all units as well as several other operational improvements. The overall capital upgrades were higher than initially anticipated as a

result of difficulties related to cleaning and preparing boiler tubes as well as additional upgrades identified as part of the capital project.

The capital upgrade resulted in higher throughput and lower operating costs at EFW which positively affected operating profit by \$1.0 million in the third quarter of 2010, partially offsetting the negative impact to operating profits in the first two quarters of 2010. APCo now expects the facility to positively impact the operating profit in the fourth quarter of 2010 by \$0.9 million, resulting in a minimal impact to operating profit in 2010, as compared to the same period in the prior year.

APCo Thermal Energy division's Sanger facility is expected to operate at or above APCo's expectations for the fourth quarter of 2010 and in line with 2009 results. Hydro-mulch sales are expected to remain below expectations for the remainder of the year due to the economic conditions in the U.S. but this is offset by higher revenues expected from the power plant.

APCo Thermal Energy division's Windsor Locks facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold into the ISO NE day-ahead market. For the period from October 1 through April 30, the facility did not commit any portion of such remaining available capacity to the winter 2010/2011 FRM. With the FRM clearing price of approximately \$6,800 per MW-month, APCo believes that superior economic performance will be achieved by committing the balance of all electrical capacity to the NE ISO day ahead market. Under the NE ISO rules, electrical producers are precluded from bidding any of the FRM committed electrical capacity at day ahead power prices at an implied heat rate of less than a 14,000 Btu/kWh. The Windsor Locks facility is capable of economically generating power for export in the 8,000 Btu/kWh to 9,000 Btu/kWh range and thus will be in a position to dispatch more by not being in the FRM market.

Following recent integrated resource planning hearings, the DPUC issued an order urging CL&P to open negotiations to re-contract existing merchant generating facilities within Connecticut such as the Windsor Locks facility as an alternative to satisfy the requirement for additional generating capacity in the state. APCo representatives are pursuing such negotiations with CL&P as potential alternative operating regime to participation in the merchant NE ISO market.

The selected merchant operating regime is expected to negatively impact operating profit in the fourth quarter of 2010 by approximately U.S. \$1.2 million compared to the same period a year ago. For a more detailed description of the options and expected impact see *Development Division - Windsor Locks*.

APCo: Development Division

The Development division works to identify, develop and construct new, renewable and efficient energy generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APCo's existing facilities. Development is focused on projects within North America with a commitment to working proactively with all stakeholders, including local communities. The Development division is led by five full time employees who have access to, and support from, all of APCo's available resources to assist it in the development of projects. Typically, the division draws upon the support of the finance, engineering, technical services, and environmental and regulatory compliance groups. It also utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains expertise, as required, from the financial, legal, engineering, technical, and construction sectors.

The Development division may also create opportunities through the acquisition of operating assets with accretive characteristics and prospective projects that are at various stages of development. The Development division believes that the prevailing economic climate has also created opportunities for APCo to acquire third party development projects on terms that require the experience and financial resources that APCo has at its disposal. The strategy is to focus on high quality renewable and high efficiency thermal energy generation projects that benefit from low operating costs using proven technology that can generate sustainable and increasing operating profit in order to achieve a high return on invested capital.

APCo's approach to project development is to maximize the utilization of internal resources while minimizing external costs. This allows development projects to evolve to the point where most major elements and uncertainties of a project are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a power purchase agreement, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that APCo will begin construction.

Industry Outlook

Environmental concerns, increases in electricity demand and fossil fuel price volatility, have combined to create the impetus for governments, regulatory bodies and utilities to diversify their mix of power generation. This diversification has largely been focused on developing a larger proportion of renewable power and high-efficiency gas generation. Consequently, a favourable policy environment has emerged for independent producers and developers of renewable and power generation, particularly in the areas of wind, hydroelectric and natural gas generation. Additionally, there has been a general recognition that power derived from independent sources that are subject to greater market competition offer a lower cost means of production.

An increasing amount of attention has been paid to the environmental value of both renewable and efficient means of power production and the ability of the power industry to offset the ill-effects of

production by higher polluting fossil fuels. To the extent that a renewable or efficient source of energy can offset a fossil fuelled generating source, it can, in some cases, generate a carbon credit which can then be sold to a third party. Despite the fact that there is no nationally recognized carbon reduction program in either the United States or Canada, there remain several regional organizations that have been established with targets to reduce carbon emissions. Globally, the value of the carbon market doubled for two consecutive years from U.S. \$31.2 billion in 2006 to U.S. \$138.9 billion in 2009. This should enhance the ability to develop future renewable sources of generation.

Divisional Outlook - Development

It is anticipated that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the U.S., continue to increase targets for renewable and other clean power generation projects. In May 2009, the Ontario government passed the Green Energy Act ("GEA"). Accordingly the Ontario Power Authority ("OPA") has issued standard pricing for electricity from renewable sources under a Feed-in Tariff. Included within this legislation is the requirement for OPA to purchase power generated from green energy projects, and an obligation for all utilities to grant priority grid access to such projects. The intention of the legislation is to make development of renewable energy projects significantly easier than the prior process of formal bids in response to requests for proposals from the responsible power authority.

Other jurisdictions have passed similar legislation. British Columbia has announced the Clean Energy Act and Nova Scotia is pursuing the 2010 Renewable Electricity Plan and its ensuing Community Feed-In-Tariff Program (COMFIT). Both of these proposed pieces of legislation have set aggressive targets for the development of new, renewable power production. They also introduce the concept of fixed pricing based on a feed-in-tariff for some categories of new renewable power projects. The combination of increased renewable production targets and appropriate fixed pricing will present investment opportunities for APCo to consider in the future.

Future Development Projects – Greenfield Projects

There are a number of future greenfield development projects which are being actively pursued by the Development division. These projects encompass several new wind energy projects, hydroelectric projects at different stages of investigation, and thermal energy generation projects. The projects being examined are located both in Canada and the U.S.

In addition to the second phase of the Red Lily I project, APCo is currently collecting wind data on three sites in Saskatchewan and responded to Saskatchewan's Request for Qualifications during the first quarter of 2010 to procure up to 175MW of wind power from one or more independent power producers. These sites have met the qualifications and APCo will likely submit project proposals into future RFPs.

In May 2009, Hydro Québec released the details of a community based tender for wind projects with a maximum of 25 MW. APCo has maintained land option agreements for two wind projects in Quebec in anticipation of future provincial tenders. In July 2010, APCo worked successfully with Société en Commandite Val-Eo, a cooperative with a development project located in the Lac Saint-

Jean region of Quebec, and the community of Saint-Damase to submit proposals into the RFP. APCo expects the results of the RFP to be announced at the end of the fourth quarter of 2010.

Discussions with the OPA indicate that energy procurement initiatives have been positively influenced by the GEA which received Royal Assent last year. The GEA is intended to provide the catalyst for the development of 50,000 new green economy jobs and is viewed by APCo as positive for the development of renewable energy in Ontario. The Development division is maintaining relationships with potential partners for the development of a number of projects that could qualify under anticipated procurement initiatives undertaken by the OPA in accordance with the GEA.

APCo has submitted applications for approximately 120 MW of on-shore wind energy projects in eastern Ontario under the GEA's Feed-in Tariff program ("FIT"). The on-shore wind price set by the FIT program is \$0.135 per KWh. APCo has received confirmation from the OPA that the applications submitted under the FIT program are being processed. The assessment process including the completion of the initial economic connection test are anticipated to be announced in the fourth quarter of 2010.

APCo has applied to become applicant of record for three crown land sites in Ontario under the Ministry of Natural Resources wind power site release program.

Each project being contemplated is subject to a significant level of due diligence and financial modeling to ensure it satisfies return and diversification objectives established for the Development division. Accordingly, the likelihood of proceeding with some or all of these projects depends on the outcome of due diligence, material contract negotiations, the structure of future calls for tender, and request for proposal programs. To maximize APCo's opportunities for development, new renewable and high efficiency thermal energy generating facilities are being pursued utilizing a variety of technologies and in diverse geographic locations.

Current Development Projects

Red Lily I

On April 21, 2010, APUC announced that it has entered into agreements to provide development, construction, operation and supervision services related to the construction, commissioning and operation of Red Lily I in south-eastern Saskatchewan. The construction phase of the project is presently nearing completion. Red Lily I will consist of 16 Vestas V82 wind turbine generators. The power purchase agreement with SaskPower is for 25 years and includes a 2% annual increase throughout the term of the agreement.

The equity in Red Lily I is owned by Concord Pacific Group, an independent investor. The facility is being financed by \$17.5 million of senior and subordinated debt from APUC, senior debt from third party lenders of \$31.0 million and an equity contribution from the independent investor of \$19.0 million. As part of the financing provided by APUC, an amount of \$6.6 million of subordinated debt has been provided to Red Lily I, bearing an interest rate of 12.5%. Subsequent to the end of the quarter on October 28, 2010, APUC funded \$2.0 million of senior debt to the project. With the commencement of construction of Red Lily I, in the three and nine months ended September 30,

2010, APCo earned construction supervision fees of approximately \$0.6 million and \$1.4 million respectively and will earn a total of approximately \$2.2 million over the construction of the project.

APUC has been granted an option to subscribe for a 75% equity interest in the project in exchange for its subordinated debt commitment of up to \$19.5 million, exercisable five years following commissioning of the project. The estimated commercial operation date for the project is the end of February 2011.

Red Lily II

In addition, APCo has secured additional land options related to property around Red Lily I to facilitate a possible 106 MW expansion ("Phase II"). The viability of the expanded project will be conditional upon satisfactory actual operating results from Red Lily I. During the first quarter of 2010, APCo responded to the request for quotations issued by SaskPower by submitting requested information pertaining to Phase II.

Successful development of wind projects is subject to significant risks and uncertainties including the ability to obtain financing on acceptable terms within deadlines imposed by the utility, reaching agreement with any other external parties involved in the project, currency fluctuations affecting the cost of major capital components such as wind turbines, price escalation for construction labour and other construction inputs and construction risk that the project is built without mechanical defects and is completed on time and within budget estimates.

Windsor Locks

The Windsor Locks facility is a 54MW natural gas power generating station located in Windsor Locks, Connecticut. Prior to April 2010, the facility delivered energy pursuant to two key off-take agreements: under the first agreement, the facility delivered 100% of its steam capacity and a portion of its electrical generating capacity to Ahlstrom Windsor Locks, LLC ("Ahlstrom"), a leading paper and non woven materials manufacturer, pursuant to an energy services agreement ("ESA") which expires in 2017 and the balance of its electrical generating capacity was delivered, to CL&P under an energy and capacity purchase agreement which expired in 2010.

Following expiration of the CL&P power purchase agreement, the electrical generating capacity not committed to Ahlstrom under the ESA has been sold into the NE ISO day-ahead electrical market. APCo has entered into an agreement with a subsidiary of Emera to manage the off-take sales from this facility into the ISO NE market. For the period June through September 2010, APCo committed approximately 26MW of the available electrical capacity to the FRM. For the period from October 1 through April 30, the facility did not commit any portion of such remaining available capacity to the winter 2010/2011 FRM. With the forward reserve market clearing price of approximately \$6,800 per MW-month, APCo believes that superior economic performance will be achieved by committing the balance of all electrical capacity to the NE ISO day ahead market (under the NE ISO rules, electrical producers are precluded from bidding any of the FRM committed electrical capacity at day ahead power prices at an implied heat rate of less than a 14,000 Btu/kWh. The Windsor Locks facility is capable of generating power for export in the 8,000 to 9,000 range and thus will be dispatched more by not being in the FRM market.

APCo is continuing the preliminary engineering and environmental permitting work for the installation of a 14.2 MW combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of Ahlstrom. The total expected capital cost for this project is estimated at approximately U.S. \$17.3 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to US \$450/KW to a maximum of US \$6.6 million to offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to Windsor Locks of approximately \$500,000/year. In addition to installing the new gas turbine, APCo would expect to continue to operate and maintain the existing equipment. Any investment in new capital for this site will be based on an assessment of the incremental earnings against such additional investment.

As an alternative to the 14.2 MW repowering project APCo participated in the integrated resource planning process conducted by the DPUC. In the resultant order issued following this process, DPUC encouraged the Connecticut regulated electricity utilities to take advantage of existing available generating capacity in the state by negotiating new power purchase agreements with facilities such as the Windsor Locks facility. Following the issuance of such order, APCo has entered into negotiations with a number of the regulated electrical utilities in Connecticut with regards to a revised power purchase agreement.

During 2010, it is expected that APCo will continue to earn revenue from steam and electrical sales to Ahlstrom, steam and electrical capacity payments made by Ahlstrom, as well as energy sales to ISO NE, capacity payments made by ISO NE. Under this operating protocol APCo will need to acquire 0.8 million MMBTU to 1.0 million MMBTU of natural gas annually in addition to the natural gas purchases reimbursed by Ahlstrom.

Other

APCo has completed preliminary engineering and a financial feasibility analysis on a 12 MW combined cycle high efficiency thermal energy generation project located in Ontario. APCo believes this project is an excellent fit for the Minister of Energy and Infrastructure's Directive to procure electricity from combined heat and power projects.

Future Development Projects – Existing Facilities

The following sets out a summary of potential development projects at existing facilities which are being examined by the Development division.

Renewable Energy

APCo is exploring multiple options related to the St. Leon facility including pursuing a future adjacent project and/or pursuing an increase in the installed capacity of the existing facility. The projects being reviewed have a potential generation capacity of over 85 MW. In the event these projects are developed, it is currently estimated to require an investment of approximately \$250 million.

LIBERTY WATER

	Nine months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Number of				
Wastewater connections			35,277	34,555
Wastewater treated (millions of gallons)			1,500	1,425
Water distribution connections			37,450	36,841
Water sold (millions of gallons)			4,100	4,500
	US \$	US \$	Can \$	Can \$
Assets for regulatory purposes (U.S. \$)	154,054	149,047		
Revenue				
Wastewater treatment	\$ 14,645	\$ 13,456	\$ 15,267	\$ 15,767
Water distribution	11,781	11,499	12,281	13,474
Other Revenue	414	499	454	585
	\$ 26,840	\$ 25,454	\$ 28,002	\$ 29,826
Expenses				
Operating expenses	(16,107)	(15,397)	(16,829)	(18,182)
Other income	65	1,204	68	1,411
Business Unit operating profit (including other income)	\$ 10,798	\$ 11,261	\$ 11,241	\$ 13,055

Liberty Water is committed to being a leading utility provider of safe, high quality and reliable water and wastewater services while providing stable and predictable earnings from its utility operations. Liberty Water has presented the division's results in both the reporting currency and its functional currency. Liberty Water believes that since the division's operations are entirely in the U.S., it is useful to show the results without the impact of foreign exchange.

Liberty Water reports total connections, inclusive of vacant connections rather than customers. Liberty Water had 35,277 wastewater connections as at September 30, 2010, as compared to 34,555 as at September 30, 2009, an increase of 722 in the period or 2.1%. Liberty Water had 37,450 water distribution connections as at September 30, 2010, as compared to 36,841 as at September 30, 2009, representing an increase of 609 in the period or 1.7%. Total connections include approximately 2,000 vacant wastewater connections and 1,300 vacant water distributions connections. Bad debt expense in the nine months ended September 30, 2010 has remained consistent with the comparable period at approximately \$0.1 million. Liberty Water's change in water distribution and wastewater treatment customer base during the period is primarily due to the acquisition of a small utility in Texas during the first quarter of 2010 and modest growth at Liberty Water's other facilities.

Liberty Water has investments in regulatory assets of U.S. \$154.1 million across four states as at September 30, 2010, as compared to U.S. \$149.0 million as at September 30, 2009 and has completed proceedings in Texas and has active proceedings in Arizona to allow it to earn its full regulatory return on its investment in regulatory assets.

2010 Nine Month Operating Results

During the nine months ended September 30, 2010, Liberty Water provided approximately 4.1 billion U.S. gallons of water to its customers, treated approximately 1.5 billion U.S. gallons of wastewater and sold approximately 255 million U.S. gallons of treated effluent.

For the nine months ended September 30, 2010, Liberty Water's revenue totalled U.S. \$26.8 million as compared to U.S. \$25.5 million during the same period in 2009, an increase of U.S. \$1.4 million or 5.4%.

Revenue from water distribution totalled U.S. \$11.8 million as compared to U.S. \$11.5 million during the same period in 2009, an increase of U.S. \$0.3 million or 2.5%. The nine month water distribution revenue was impacted by an increase of U.S. \$0.4 million at the four Texas Silverleaf facilities primarily due to the implementation of interim rate increases and U.S. \$0.2 million related to the acquisition of a facility in Galveston, Texas ("Galveston") in the first quarter of 2010, partially offset by decreased revenue of U.S. \$0.3 million primarily due to lower commercial water sales at the LPSCo facility as compared to the same period in 2009.

Revenue from wastewater treatment totalled U.S. \$14.6 million, as compared to U.S. \$13.5 million during the same period in 2009, an increase of U.S. \$1.2 million or 8.8%. The nine month wastewater treatment revenue was impacted by increased revenue of U.S. \$1.0 million at the four Texas Silverleaf facilities, the Woodmark facility and the Tall Timbers facility, primarily due to the implementation of interim rate increases, U.S. \$0.1 million at LPSCo primarily due to higher residential revenues, U.S. \$0.2 million related to the acquisition of Galveston as compared to the same period in 2009. These increases were partially offset by decreased wastewater treatment revenue of U.S. \$0.1 million due to lower treated effluent revenue at the Gold Canyon facility and lower customer demand at two wastewater treatment facilities as compared to the same period in 2009.

For the nine months ended September 30, 2010, operating expenses totalled U.S. \$16.1 million, as compared to U.S. \$15.4 million during the same period in 2009. Overall expenses increase U.S. \$0.7 million or 4.6% as compared to the same period in 2009. Operating expenses increased U.S. \$1.2 million as a result of increased wages, salary and other operating costs and U.S. \$0.2 million as a result of increased equipment rental and transportation costs, partially offset by decreases of U.S. \$0.1 million in reduced repair and maintenance expenses and U.S. \$0.4 million in reduced contracted services expenses as compared to the same period in 2009. The comparable period includes expenses of U.S. \$0.6 million related to rate case costs. As a result of the adoption of rate regulated accounting during the fourth quarter of 2009, these costs are being capitalized in the current period.

During the nine months ended September 30, 2009, Liberty Water earned other income of U.S. \$1.2 million on the disposition of excess land. During the nine months ended September 30, 2010, Liberty Water did not dispose of any significant land or other assets.

For the nine months ended September 30, 2010, Liberty Water's operating profit totalled U.S. \$10.8 million as compared to U.S. \$11.3 million in the same period in 2009, a decrease of U.S. \$0.5 million or 4.1%. Excluding the gain on disposition of other assets, operating profits increased by \$0.7 million or 6.7%. Liberty Water's operating profit did not meet expectations for the nine months ended September 30, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

Measured in Canadian dollars, for the nine months ended September 30, 2010, Liberty Water's revenue totalled \$28.0 million as compared to \$29.8 million during the same period in 2009, a decrease of \$1.8 million. Revenue from wastewater treatment totalled \$15.3 million, as compared to \$15.8 million during the same period in 2009, a decrease of \$0.5 million. Revenue from water distribution totalled \$12.3 million, as compared to \$13.5 million during the same period in 2009, a decrease of \$1.2 million. Liberty Water reported decreased revenue from operations of \$3.2 million in the first nine months of 2010 as a result of the stronger Canadian dollar as compared to the same period in 2009.

Measured in Canadian dollars, for the nine months ended September 30, 2010, operating expenses totalled \$16.8 million, as compared to \$18.2 million during the same period in 2009. Liberty Water reported lower expenses from operations of \$2.1 million as a result of the stronger Canadian dollar, as compared to the same period in 2009.

For the nine months ended September 30, 2010, Liberty Water's operating profit totalled \$11.2 million as compared to \$13.1 million in the same period in 2009, a decrease of \$1.8 million or 13.9%. Excluding the gain on disposition of other assets, operating profits decreased by \$0.5 million or 4.7%. Liberty Water's operating profit did not meet expectations for the nine months ended September 30, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

	Three months ended September 30		Three months ended September 30	
	2010	2009	2010	2009
Number of				
Wastewater connections			35,277	34,555
Wastewater treated (millions of gallons)			475	475
Water distribution connections			37,450	36,841
Water sold (millions of gallons)			1,800	1,900

	Three months ended September 30		Three months ended September 30	
	2010 US \$	2009 US \$	2010 Can \$	2009 Can \$
Assets for regulatory purposes (U.S. \$)	154,054	152,069		
Revenue				
Wastewater treatment	\$ 5,090	\$ 4,616	\$ 5,321	\$ 5,217
Water distribution	4,555	4,270	4,762	4,826
Other Revenue	137	158	165	179
	\$ 9,782	\$ 9,044	\$ 10,248	\$ 10,222
Expenses				
Operating expenses	(5,643)	(5,483)	(5,921)	(6,185)
Other income	55	1,281	57	1,448
Business Unit operating profit (including other income)	\$ 4,194	\$ 4,842	\$ 4,384	\$ 5,485

2010 Third Quarter Operating Results

During the quarter ended September 30, 2010, Liberty Water provided approximately 1.8 billion U.S. gallons of water to its customers, treated approximately 475 million U.S. gallons of wastewater and sold approximately 115 million U.S. gallons of treated effluent.

For the quarter ended September 30, 2010, Liberty Water's revenue totalled U.S. \$9.8 million as compared to U.S. \$9.0 million during the same period in 2009, an increase of U.S. \$0.7 million or 8.2%.

Revenue from water distribution totalled U.S. \$4.6 million, as compared to U.S. \$4.3 million during the same period in 2009, an increase of U.S. \$0.3 million or 6.7%. The third quarter water distribution revenue was impacted by an increase of \$0.2 million at the four Texas Silverleaf facilities primarily due to the implementation of interim rate increases and U.S. \$0.1 million related to the acquisition of Galveston as compared to the same period in 2009. These increases were partially offset by lower customer demand at four wastewater treatment facilities as compared to the same period in 2009.

Revenue from wastewater treatment totalled U.S. \$5.1 million, as compared to U.S. \$4.6 million during the same period in 2009, an increase of U.S. \$0.5 million. The third quarter wastewater treatment revenue was impacted by increased revenue of U.S. \$0.4 million at the four Texas Silverleaf facilities, the Woodmark facility and the Tall Timbers facility, primarily due to the implementation of interim rate increases, and U.S. \$0.1 million at the Black Mountain facility primarily due to higher residential revenue as compared to the same period in 2009. These increases were partially offset by decreased wastewater treatment revenue of U.S. \$0.2 million due to lower treated effluent revenue the Gold Canyon facility as well as lower customer demand at two wastewater treatment facilities as compared to the same period in 2009.

For the quarter ended September 30, 2010, operating expenses totalled U.S. \$5.6 million, as compared to U.S. \$5.5 million during the same period in 2009. Overall expenses increased U.S. \$0.1 million or 2.9% as compared to the same period in 2009. Operating expenses increased U.S. \$0.1 million as a result of increased wages, salary and other operating costs, partially offset by decreases of U.S. \$0.1 million in reduced contracted services expenses and \$0.1 million in reduced repair and maintenance expenses as compared to the same period in 2009. The comparable period includes expenses of U.S. \$0.2 million related to rate case costs. As a result of the adoption of rate regulated accounting during the fourth quarter of 2009, these costs are being capitalized in the current period.

During the three months ended September 30, 2009, Liberty Water earned other income of U.S. \$1.2 million on the disposition of excess land. During the three months ended September 30, 2010, Liberty Water did not dispose of any significant land or other assets.

For the quarter ended September 30, 2010, Liberty Water's operating profit totalled U.S. \$4.2 million as compared to U.S. \$4.8 million in the same period in 2009, a decrease of U.S. \$0.6 million or 13.4%. Excluding the gain on disposition of other assets, operating profits increased by \$0.6 million or 16.2%. Liberty Water's operating profit did not meet expectations for the three months ended September 30, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

Measured in Canadian dollars, for the quarter ended September 30, 2010, Liberty Water's revenue totalled \$10.2 million, consistent with the same period in 2009. Revenue from wastewater treatment totalled \$5.3 million, as compared to \$5.2 million during the same period in 2009, an increase of \$0.1 million. Revenue from water distribution totalled \$4.8 million, consistent with the same period in 2009. Liberty Water reported decreased revenue from operations of \$0.7 million in the third quarter of 2010 as a result of the stronger Canadian dollar as compared to the same period in 2009.

Measured in Canadian dollars, for the quarter ended September 30, 2010, operating expenses totalled \$5.9 million, as compared to \$6.2 million during the same period in 2009. Liberty Water reported lower expenses from operations of \$0.4 million as a result of the stronger Canadian dollar, as compared to the same period in 2009.

For the quarter ended September 30, 2010, Liberty Water's operating profit totalled \$4.4 million as compared to \$5.5 million in the same period in 2009, a decrease of \$1.1 million. Excluding the gain on disposition of other assets, operating profits increased by \$0.3 million or 7.2%. Liberty Water's operating profit did not meet expectations for the three months ended September 30, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

Outlook – Liberty Water

Liberty Water is expecting modest customer growth in the remainder of fiscal 2010. Liberty Water provides water distribution and wastewater collection and treatment services, primarily in the southern and southwestern U.S. where communities have traditionally experienced long term growth and that provide continuing future opportunities for organic growth.

Revenue increases from rate cases completed in Arizona and Texas have contributed an additional \$2.2 million in annualized run rate revenue. Liberty Water has also received a ROO that recommends an additional \$8.1 million for its Litchfield Park facility. This ROO is subject to final approval of the ACC. It is anticipated that a final order for this ROO will be received in the fourth quarter of 2010. Additional rate cases with revenue increases requests of \$3.5 million in annualized run rate revenue are expected to be achieved by the first quarter of 2011. Liberty Water understands that there are an unusually high number of active rate cases proceeding through the ACC which makes it difficult to provide an estimate of the extent of any further increased revenues in 2010 from the rate cases. However, Liberty Water still expects the substantial impact of additional revenues from rate cases to be achieved in 2011.

Liberty Water continues to work with key stakeholders, including regulators, to help manage issues related to the issuance of decisions in its rate cases in a timely manner.

Completed Rate Cases	Annual U.S. \$ Revenue Increase as Filed	Annual U.S. \$ Revenue Increase
Facility		
Arizona		
Black Mountain*	\$ 0.9 million	\$ 0.7 million
Litchfield Park Service Company**	\$ 12.5 million	\$ 8.1 million
Texas		
Texas Utilities (Silverleaf – 4 utilities)***	\$ 1.2 million	\$ 1.2 million
Tall Timbers ****	\$ 0.2 million	\$ 0.2 million
Woodmark***	\$ 0.1 million	\$ 0.1 million

* New rates implemented on September 1, 2010.

** Recommended Order & Opinion received on October 5, 2010. New rates anticipated to be implemented on November 1, 2010.

*** New rates implemented. Final order approved by the Office of the Executive Director of the Texas Commission on Environmental Quality ("TCEQ") and the Office of the Public Interest Counsel ("OPIC").

**** New rates implemented. Final order subject to approval of the TCEQ and the OPIC.

Rate Cases Awaiting Recommended Order & Opinion	Estimated Annual U.S. \$ Revenue Increase as Filed
Facility	
Arizona	
Bella Vista, Northern and Southern Sunrise	\$ 1.5 million
Rio Rico	\$ 2.0 million

Rate cases seek to ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Water monitors current and anticipated

operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments.

In Arizona, the ACC requires a full regulatory process for all rate cases using a historic test year. On August 5, 2010, Liberty Water received a ROO for its Black Mountain Sewer Company recommending a rate increase of approximately \$0.7 million. The ROO was approved in entirety at the Commission's open meeting held in August. On October 5, 2010, Liberty Water received a ROO for its Litchfield Park Service Company proposing an annualized revenue increase of \$8.1 million and this increase is expected to be implemented in November 2010. It is anticipated that the regulatory review of the proposed rates and tariffs for the remaining Arizona facilities would be completed in 2010 or early 2011.

In Texas, the TCEQ allows the utility's customers a period of 90 days from the effective date of the proposed rates to object to the imposition of interim rates pending final rates determination. If greater than 10% of a specific Texas utility's customers object to the new proposed rates, the proposed rates would be subjected to a full regulatory hearing process administered by the TCEQ in order to finalize the rates. If fewer than 10% of the customers record an objection to the proposed rates, those proposed rates are likely to be adopted and declared final as proposed. Any difference between the interim rates charged and collected and the final rates as approved by TCEQ will be subject to a retroactive adjustment and refund on the customers' subsequent monthly bill.

Liberty Water has entered into negotiated settlements with the customers of the Texas Silverleaf and Tall Timbers facilities, resulting in the achievement of the full estimated annualized revenue increase of \$1.2 million and \$0.2 million, respectively. The Woodmark facility did not receive objections from 10% of the customer base and is also expected to achieve the full estimated annualized revenue increase of \$0.1 million. The Tall Timbers rate case is pending final approval from the TCEQ Executive Director.

APUC: Corporate

	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Corporate and other expenses:				
Administrative expenses	3,855	3,250	9,760	8,181
Management costs	-	213	-	639
Loss / (Gain) on foreign exchange	(841)	313	(474)	(1,003)
Interest expense	6,480	5,086	18,893	15,742
Interest, dividend and other Income	(937)	(734)	(2,614)	(2,248)
Loss (gain) on derivative financial instruments	805	(7,100)	2,945	(15,803)
Income tax recovery	(2,069)	(2,924)	(4,689)	(7,265)

2010 Nine Month Corporate and Other Expenses

During the nine months ended September 30, 2010, management and administrative expenses totalled \$9.8 million, as compared to \$8.8 million in the same period in 2009. The expense increase in the nine months ended September 30, 2010 results from increased capital taxes resulting from APUC's effective conversion to a corporation in 2009, developing the US GAAP conversion plan and additional salaries related to administering APUC's operations as compared to the same period in 2009.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and working capital balances held by Canadian operating entities and do not impact current cash position. During the nine months ended September 30, 2010, APUC classified all of its power generation operating facilities based in the U.S. as self sustaining. As a result, changes in the values of U.S. denominated debt and working capital balances in these U.S. operating entities after January 1, 2010 no longer flow through the consolidated statement of operations. For the nine months ended September 30, 2010, APUC reported a foreign exchange gain of \$0.5 million as compared to a gain of \$1.0 million during the same period in 2009. The nine months ended September 30, 2010 experienced a decrease in value of the U.S. dollar of 2.1% which resulted in unrealized gains on APUC's U.S. dollar denominated debt and working capital balances held by Canadian entities. In the comparable period in 2009, APUC's power generation operating facilities based in the U.S. were classified as integrated and the decrease in the value of the U.S. dollar of 12.5% experienced in the period resulted in unrealized gains on APUC's U.S. dollar denominated debt and working capital balances held by its integrated U.S. operating facilities.

For the nine months ended September 30, 2010, interest expense totalled \$18.9 million as compared to \$15.7 million in the same period in 2009. Interest expense increased as a result of higher levels of convertible debentures, partially offset by decreased interest expense resulting from lower interest rates charged and lower average borrowings on APUC's variable interest rate credit facilities, as compared to the prior year.

For the nine months ended September 30, 2010, interest, dividend and other income totalled \$2.6 million as compared to \$2.2 million in the same period in 2009. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities and interest related to APUC's subordinated debt interest in the Red Lily I project. The income earned on the investments in the Kirkland and Cochrane facilities was previously allocated to interest and other income in the Thermal Energy division.

Loss on derivative financial instruments consists of realized and unrealized mark-to-market losses on foreign exchange forward contracts, interest rate swaps and forward energy contracts during the quarter. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of \$4.7 million was recorded in the nine months ended September 30, 2010, as compared to a recovery of \$7.3 million during the same period in 2009. The decrease is primarily because a higher amount of income tax recovery was set up on net operating losses and disallowed

interest expenses generated from the US entities as of September 30, 2009. On October 27, 2009, Algonquin effectively converted from a publicly traded income trust to a publicly traded corporation. APUC's calculation of current and future income taxes for the nine months ended September 30, 2010 is based on its new corporate structure effective October 27, 2009, whereas the calculation of current and future income taxes for the quarter ended September 30, 2009 is based on a publicly traded income trust structure. Included in future income tax recoveries for the nine months ended September 30, 2010 are \$4.2 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

2010 Third Quarter Corporate and Other Expenses

During the quarter ended September 30, 2010, management and administrative expenses totalled \$3.9 million, as compared to \$3.5 million in the same period in 2009. The expense increase in the three months ended September 30, 2010 results from those factors identified in the discussion of the nine month expense noted above as compared to the same period in 2009.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and working capital balances held by Canadian operating entities and do not impact current cash position. For the three months ended September 30, 2010, APUC reported a foreign exchange gain of \$0.8 million as compared to a loss of \$0.3 million during the same period in 2009. The three months ended September 30, 2010 experienced an decrease in value of the U.S. dollar of 3.3% which resulted in unrealized gains on APUC's U.S. dollar denominated debt and working capital balances held by Canadian entities. In the comparable period in 2009, APUC's power generation operating facilities based in the U.S. were classified as integrated and the decrease in the value of the U.S. dollar of 7.9% experienced in the quarter resulted in unrealized gains on APUC's U.S. dollar denominated debt and working capital balances held by its integrated U.S. operating facilities.

For the quarter ended September 30, 2010, interest expense totalled \$6.5 million as compared to \$5.1 million in the same period in 2009. Interest expense increased as a result of higher levels of convertible debentures, and increased average interest rates charged on APUC's variable interest rate credit facilities, partially offset by lower average borrowings on APUC's variable interest rate credit facilities, as compared to the prior year.

For the quarter ended September 30, 2010, interest, dividend and other income totalled \$0.9 million as compared to \$0.7 million in the same period in 2009. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities and interest related to APUC's subordinated debt interest in the Red Lily I project. The income earned on the investments in the Kirkland and Cochrane facilities was previously allocated to interest and other income in the Thermal Energy division.

Loss on derivative financial instruments consists of realized and unrealized mark-to-market losses on foreign exchange forward contracts, interest rate swaps and forward energy contracts during the

quarter. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of \$2.1 million was recorded in the three months ended September 30, 2010, as compared to a recovery of \$2.9 million during the same period in 2009. The decrease is primarily because a higher amount of income tax recovery was set up on net operating losses and disallowed interest expenses generated from the US entities as of September 30, 2009. On October 27, 2009, Algonquin effectively converted from a publicly traded income trust to a publicly traded corporation. APUC's calculation of current and future income taxes for the nine months ended September 30, 2010 is based on its new corporate structure effective October 27, 2009, whereas the calculation of current and future income taxes for the quarter ended September 30, 2009 is based on a publicly traded income trust structure. Included in future income tax recoveries for the nine months ended September 30, 2010 are \$4.2 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

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 which are derived from a number of non-operating factors, accounting methods and assumptions. 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 September 30		Nine months ended September 30	
	2010	2009	2010	2009
Net earnings	\$ 1,533	\$ 13,078	\$ 2,751	\$ 32,623
Add:				
Income tax recovery	(2,069)	(2,924)	(4,689)	(7,265)
Interest expense	6,480	5,086	18,893	15,742

	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
(Gain) / loss on derivative financial instruments	805	(7,100)	2,945	(15,803)
(Gain) / loss on foreign exchange	(841)	313	(474)	(1,003)
Amortization	11,753	11,513	34,673	34,533
Other	105	310	315	2,514
Adjusted EBITDA	\$ 17,766	\$ 20,276	\$ 54,414	\$ 61,341

For the nine months ended September 30, 2010, Adjusted EBITDA totalled \$54.4 million as compared to \$61.3 million, a net decrease of \$6.9 million or 11.3% as compared to the same period in 2009. For the quarter ended September 30, 2010, Adjusted EBITDA totalled \$17.8 million as compared to \$20.3 million, a decrease of \$2.5 million or 12.4% as compared to the same period in 2009. The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

	Three months ended September 30 2010	Nine months ended September 30 2010
Comparative Prior Period Adjusted EBITDA	\$ 20,276	\$ 61,341
Significant Changes:		
Renewable – primarily due to lower hydrology	(3,000)	(3,900)
Lower results from stronger Canadian dollar	(500)	(2,600)
St. Leon - primarily due to a lower wind resource	(200)	(2,300)
EFW – impact of shutdown	1,200	(2,800)
Liberty Water gain on sale of excess land	(1,400)	(1,400)
Administration costs	200	(800)
Tinker/AES	1,400	7,000
Red Lily – development fees	500	1,500
Liberty Water completed rate cases	600	700
Other	(1,310)	(2,327)
Current Period Adjusted EBITDA	\$ 17,766	\$ 54,414

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 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 as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. APUC uses adjusted net earnings to assess the performance of APUC without the effects of gains or losses on foreign exchange, foreign exchange forward contracts and interest rate swaps 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 APUC's 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 September 30		Nine months ended September 30	
	2010	2009	2010	2009
Net earnings	\$ 1,533	\$ 13,078	\$ 2,751	\$ 32,623
Add:				
Loss (gain) on derivative financial instruments, net of tax	181	(6,148)	1,451	(12,621)
Loss (gain) on foreign exchange, net of tax	(841)	313	(474)	(1,003)
Adjusted net earnings	\$ 873	\$ 7,243	\$ 3,728	\$ 18,999
Adjusted net earnings per share/trust unit*	\$ 0.01	\$ 0.09	\$ 0.04	\$ 0.24

* Algonquin converted to a corporation on October 27, 2009. Earnings prior to this date represent earnings per trust unit.

For the nine months ended September 30, 2010, adjusted net earnings totalled \$3.7 million as compared to \$19.0 million, a decrease of \$15.3 million as compared to the same period in 2009. The decrease in adjusted net earnings in the nine months ended September 30, 2010 is primarily due to lower earnings from operations, higher interest expense and lower future income tax recoveries as compared to the same period in 2009.

For the three months ended September 30, 2010, adjusted net earnings totalled \$0.9 million as compared to adjusted net earnings of \$7.2 million, a decrease of \$6.4 million as compared to the same period in 2009. The decrease in adjusted net earnings in the three months ended September

30, 2010 is primarily due to lower interest, dividend and other income, higher interest expense and lower future income tax recoveries as compared to the same period in 2009.

Summary of Property, Plant and Equipment Expenditures

	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
APCo				
Renewable Energy Division				
Capital expenditures	\$ 409	\$ 129	\$ 1,352	\$ 634
Acquisition of operating entities	-	-	40,281	-
Total	\$ 409	\$ 129	\$ 41,633	\$ 634
Thermal Energy Division				
Capital expenditures	\$ 1,231	\$ 883	\$ 11,162	\$ 2,857
Total	\$ 1,231	\$ 883	\$ 11,162	\$ 2,857
LIBERTY WATER				
Capital Investment in regulatory assets	\$ 1,024	\$ 2,283	\$ 2,060	\$ 6,601
Acquisition of operating entities	-	-	2,121	-
	\$ 1,024	\$ 2,283	\$ 4,181	\$ 6,601
Consolidated (includes Corporate)				
Capital expenditures	\$ 1,642	\$ 1,020	\$ 12,593	\$ 3,598
Capital investment in regulatory assets	1,024	2,283	2,060	6,601
Acquisition of operating entities	364	113	43,094	860
Total	\$ 3,030	\$ 3,416	\$ 57,747	\$ 11,059

APUC's consolidated capital expenditures in the nine months ended September 30, 2010 increased as compared to the same period in 2009 primarily due to the major capital upgrades completed at the EFW facility, the acquisition of the Tinker Assets and the Energy Services Business as well as the acquisition by Liberty Water of a water distribution and wastewater treatment facility in Texas.

Property, plant and equipment expenditures for the remainder of the 2010 fiscal year are anticipated to be between \$3.0 million and \$5.5 million, including approximately \$1.8 million related to ongoing requirements by Liberty Water, \$1.0 million related to the APCo Thermal division, and \$1.0 million related to the APCo Renewable Energy division.

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.

2010 Nine Month Property Plant and Equipment Expenditures

During the nine months ended September 30, 2010, APCo incurred capital expenditures of \$12.6 million, as compared to \$3.6 million during the comparable period in 2009. APCo also invested \$43.1 million to acquire operating assets/entities during the nine months ended September 30, 2010, as compared to \$0.9 million during the comparable period in 2009.

During the nine months ended September 30, 2010, APCo Renewable Energy division's capital expenditures were \$1.4 million, as compared to \$0.6 million in the comparable period in 2009. There were no individual projects in excess of \$0.5 million initiated in the current period. The APCo Renewable Energy division's acquisition of operating assets relate to the Tinker Assets located in New Brunswick and Maine.

During the nine months ended September 30, 2010, APCo Thermal Energy division's capital primarily relate to the EFW facility where major maintenance was completed subsequent to the end of the quarter. In the comparable period, the expenditures primarily related to minor capital projects at the hydro-mulch facility and the EFW facility.

During the nine months ended September 30, 2010, Liberty Water invested maintenance capital of \$2 million into regulatory assets, as compared to an investment of \$6.6 million in the comparable period. During the nine months ended September 30, 2010, Liberty Water acquired a water and wastewater utility near Galveston Texas for approximately \$2.0 million. In the comparable period in 2009, Liberty Water's expenditures primarily related to the completion and commissioning of projects initiated in 2008.

As previously noted, these investments, other than non-utility assets, have been included in the rate case applications currently underway. In the comparable period, the expenditures primarily related to investment in additional wells, engineering work regarding wastewater treatment operations and arsenic treatment at the LPSCo facility. The expenditures in the comparable period are included in the rate case applications which are currently in process.

2010 Third Quarter Property Plant and Equipment Expenditures

During the three months ended September 30, 2010, APCo incurred capital expenditures of \$1.6 million, as compared to \$1.0 million during the comparable period in 2009.

During the three months ended September 30, 2010, APCo Renewable Energy division's capital expenditures were not significant, consistent with the comparable period in 2009.

During the three months ended September 30, 2010, APCo Thermal Energy division's capital primarily relate to the EFW facility where major maintenance was completed subsequent to the quarter end. In the comparable period, the expenditures primarily related to minor capital projects at the hydro-mulch facility and the EFW facility.

During the three months ended September 30, 2010, Liberty Water invested maintenance capital of \$1 million into regulatory assets, as compared to \$2.3 million in the comparable period.

Liquidity and Capital Reserves

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries under the senior banking credit facilities previously arranged by Algonquin (the “Facilities”):

	2010 Q3	2010 Q2	2010 Q1	2009 Q4	2009 Q3
Committed and available Facilities	\$ 163,400	\$ 162,800	\$ 177,950	\$ 179,500	\$ 176,700
Funds Drawn on Facilities	(108,900)	(102,800)	(91,650)	(94,000)	(129,000)
Letters of Credit issued	(33,800)	(34,600)	(32,400)	(33,100)	(33,400)
Remaining available Facilities	\$ 20,700	\$ 25,400	\$ 53,900	\$ 52,400	\$ 14,300
Cash on Hand	3,100	2,400	750	2,800	7,700
Total liquidity and capital reserves	\$ 23,800	\$ 27,800	\$ 54,650	\$ 55,200	\$ 22,000

As at and for the period ended September 30, 2010, APUC and Algonquin are in compliance with the covenants under its Facilities.

As at September 30, 2010, CAD \$76.0 million and U.S. \$32.0 million had been drawn on the Facilities as compared to CAD \$94.0 million as at December 31, 2009. The increased level of borrowings on the Facilities are primarily the result of APUC’s subordinated debt investment in Red Lily I and its capital investment in the EFW facility during the quarter ended September 30, 2010. In addition to amounts actually drawn, there was \$33.8 million in letters of credit currently outstanding as at September 30, 2010. As at September 30, 2010, APUC and its subsidiaries had \$20.7 million of committed and available bank facilities remaining and \$3.1 million of cash resulting in \$23.8 million of total liquidity and capital reserves.

APUC expects to reduce its level of short term borrowings under the Facilities which mature on January 14, 2011 through obtaining appropriate long term permanent debt through refinancing certain project specific financings or additional medium to long term notes. APUC has received and is currently assessing several financing offers to term out its short term bank credit facility and expects this to close in the fourth quarter. In addition, APUC has commenced and expects to conclude negotiations with its bank syndicate on the renewal of the Facilities for a three year term following its maturity before the end of the year.

Contractual Obligations

Information concerning contractual obligations as of September 30, 2010 is shown below:

	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Long term debt obligations ¹	\$ 255,367	\$ 112,428	\$ 70,453	\$ 3,682	\$ 68,804
Convertible Debentures	\$ 186,668	-	-	63,451	123,217
Interest on long term debt obligations	\$ 136,558	20,041	36,452	31,759	48,306
Purchase obligations	\$ 26,058	26,058	-	-	-
Derivative financial instruments:					
Currency forward	\$ 742	480	262	-	-
Interest rate swap	\$ 7,772	2,891	3,125	1,756	-
Energy forward contracts	\$ 884	884	-	-	-
Capital lease obligations	\$ 581	210	369	2	-
Other obligations	\$ 10,059	507	1,015	1,015	7,522
Total obligations	\$ 624,689	\$ 163,499	\$ 111,676	\$ 101,665	\$ 247,849

¹ Includes Funds due on Facilities, which matures on January 14, 2011 and has been recorded as a current liability on the consolidated balance sheet.

Long term obligations include regular payments related to long term debt and other obligations. During the nine months ended September 30, 2010, the amount due under the Facility was reclassified as a current obligation as the term of the Facility matures on January 14, 2011.

Shareholder's Equity and Convertible Debentures

On October 27, 2009, all of Algonquin's trust units were exchanged for shares of APUC that began to be publicly traded on the Toronto Stock Exchange ("TSX") while Algonquin's trust units concurrently ceased trading on the TSX. As at September 30, 2010, APUC had 95,099,990 issued and outstanding shares.

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

In 2008, Algonquin entered into an agreement with Highground Capital Corporation ("Highground") (previously Algonquin Power Venture Fund) and CJIG Management Inc. ("CJIG") which was the manager of Highground and a related party of Algonquin controlled by the shareholders of

Algonquin Power Management Inc., the former manager of Algonquin (“APMI” or the “Manager”). Under the agreement, CJIG acquired all of the issued and outstanding common shares of Highground and Algonquin issued trust units to the Highground shareholders and CJIG.

In 2009, APUC’s consideration received from the acquisition exceeded \$26,970, the minimum contemplated under the agreements, and, as a result APUC is entitled to 50% of any additional proceeds from the assets formerly owned by Highground. CJIG is entitled to the remaining 50% of any proceeds in excess of the minimum amount. During the nine months ended September 30, 2010, APUC received \$0.2 million (2009 - \$0.3 million) from CJIG as APUC’s share of the 50% of additional proceeds from the further liquidation of the assets held by Highground. This has been recorded as an increased amount assigned to the equity originally issued.

The remaining investments, formerly held by Highground, currently consist of two non-liquid debt assets having an approximate principal amount of \$2.2 million. The payments on these assets are current and the debt matures in the fourth quarter of 2010 and 2012. APUC’s 50% share of any additional proceeds from liquidation of the remaining Highground assets will be recorded when received as additional proceeds from the issuance of equity.

As an element of its strategic partnership with Emera announced on April 23, 2009, APUC has an agreement with Emera to issue approximately 8.5 million shares of APUC at a price of \$3.25 per share. Delivery of these shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of the California Utility.

On December 21, 2009, the Board reached an agreement with the shareholders of APMI to internalize all management functions of APCo which were provided by the Manager. At the Meeting, shareholders approved the issuance of shares in respect of the internalization of management. As a result, APUC acquired the interest previously held by the Manager in the management services agreement through the issuance of 1,180,180 APUC shares during the quarter ended June 30, 2010.

On October 27, 2009, APUC issued convertible unsecured subordinated debentures bearing interest at 7.5%, maturing on November 30, 2014 (“Series 1A Debentures”) in a principal amount of \$66,943. No Series 1A Debentures were converted into shares APUC during the three months ended September 30, 2010 and a principal amount of \$3,491 Series 1A Debentures were converted 855,689 shares of APUC during the nine months ended September 30, 2010. On September 30, 2010, there were 63,451 Series 1A Debentures outstanding with a face value of \$63,451. Subsequent to the end of the quarter, \$45 Series 1A Debentures were converted to 11,066 shares.

On October 27, 2009, APUC issued convertible unsecured subordinated debentures bearing interest at 6.35%, maturing on November 30, 2016 (“Series 2A Debentures”) in a principal amount of \$59,967. On September 30, 2010 there were 59,967 Series 2A Debentures outstanding with a face value of \$59,967.

On December 2, 2009, APUC issued 63,250 convertible unsecured subordinated debentures bearing interest at 7.0%, maturing on June 30, 2017 (“Series 3 Debentures”) in a principal amount of \$63,250.

On September 30, 2010, there were 63,250 Series 3 Debentures outstanding with a face value of \$63,250. Subsequent to the end of the quarter, \$15 Series 3 Debentures were converted to 3,571 shares.

Shareholders' Rights Plan

APUC has adopted a Shareholders' Rights Plan (the "Rights Plan"). The Rights Plan is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the Board and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value. The TSX has accepted notice for filing of the Rights Plan and the Rights Plan was approved by shareholders at the Meeting until the termination of the annual general meeting of the Shareholders of APUC in 2013 or its termination under the terms of the of Rights Plan. The Rights Plan is similar to rights plans adopted by many other Canadian corporations. Until the occurrence of certain specific events, the rights will trade with the shares of APUC and be represented by certificates representing the shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it, acquires or announces its intention to acquire twenty percent or more of the outstanding shares of APUC without complying with the Permitted Bid provisions of the Plan. Should a non-Permitted Bid be launched, each right would entitle each holder of shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional shares of APUC at a fifty percent discount to the market price at the time.

It is not the intention of the Rights Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Rights Plan, a Permitted Bid is a bid made to all shareholders for all of their shares on identical terms and conditions that is open for no less than 60 days. If at the end of 60 days at least fifty percent of the outstanding shares, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the shares but must extend the bid for a further ten days to allow all other shareholders to tender.

Stock Option Plan

On June 23, 2010, APUC's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. An option holder may elect to surrender any portion of the vested options which is then exercisable in exchange for the In-the-Money Amount. In accordance with the Plan, the "In-The-Money Amount" represents the excess, if any, of the market price of a share at such time over the option price, in each case such In-the-Money amount being payable by APUC in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within

ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the Plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

Effective August 12, 2010, the Board approved the grant of 1,102,041 options to select senior executives of APUC. The options allow for the purchase of common shares at a price of \$4.05, the market price of the underlying common share at the date of grant. One-third of the options vests on each of January 1, 2011, 2012 and 2013. Options may be exercised up to eight years following the date of grant.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognised at least equals the value of the vested portion of the award at that date. For the three months ended September 30, 2010, APUC recorded \$34 in compensation expense. As at September 30, 2010, there was \$636 of total unrecognized compensation costs related to non-vested shares-based compensation arrangement granted under the Plan.

No share options were exercised in 2010 or exercisable at September 30, 2010. The intrinsic value of the 1,102,041 non-vested shares as at September 30, 2010 was \$584.

Related Party Transactions

The following related party transactions occurred during the three and nine months ended September 30, 2010:

- Up to December 21, 2009, APMI provided management services to the Fund including advice and consultation concerning business planning, support, guidance and policy making and general management services. On December 21, 2009, the Board reached an agreement ("Management Internalization Agreement") with APMI to internalize all management functions of Algonquin which were provided by APMI. Therefore, for the three and nine months ended September 30, 2010, APMI was not paid a management fee. For the three and nine months ended September 30, 2009, APMI was paid on a cost recovery basis for costs incurred and charged \$214 and \$639 respectively.
- 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 nine months ended September 30, 2010 were \$82 (2009 - \$81) and \$245 (2009 - \$249) respectively. Based on a review of the real estate leasing market at the time, APUC believes the lease was entered into on terms equivalent to fair market value for prime office space of similar size and quality.
- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. During the three and nine months ended September 30, 2010, APUC incurred costs in

connection with the use of the aircraft of \$162 (2009 - \$167) and \$370 (2009 - \$307), respectively, and amortization expense related to the advance against expense reimbursements of \$36 (2009 - \$45) and \$99 (2009 - \$118), respectively.

- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), an indirect subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a five year period commencing June 17, 2008 growing to a maximum of 10% by year fifteen. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related party holders of the Class B units are entitled to cash distributions of \$63 (2009 - \$64) and \$189 (2009 - \$221) for the three and nine months ended September 30, 2010, respectively.
- APMI is entitled to 50% of the cash flow above a 15% return on investment for the BCI project pursuant to its project management contract. During the three and nine months ended September 30, 2010 and 2009, no amounts were paid under this agreement. In 2008, APMI earned a construction supervision fee of \$100 in relation to the development of this project. As of September 30, 2010 this amount is accrued and included in accounts payable on the consolidated balance sheet.
- A member of the Board of Directors of APUC is an executive at Emera. A contract with a subsidiary of Emera to purchase energy on ISO NE and provide scheduling services on ISO NE was included as part of the acquisition of the Energy Services Business associated with the Tinker Acquisition. The contract expired in the three months ended March 31, 2010 and was not renewed. As a result of this contract, during the three months ended March 31, 2010, a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of the Energy Services Business. In this capacity, APUC paid a subsidiary of Emera an amount of \$1,368 (2009 - \$nil) which was included as an operating expense on the interim consolidated statement of operations.
- During the period ended June 30, 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During the three and nine months ended September 30, 2010 APUC paid \$71 (2009 - \$nil) and \$132 (2009 - \$nil) in relation to this contract. In the same period, APUC issued a letter of credit to a subsidiary of Emera in an amount of U.S. \$500 in conjunction with this contract.
- APUC has agreements with three hydroelectric generating facilities owned by affiliates of APMI. As a result of these agreements, APUC employees operate these hydroelectric generating facilities owned by affiliates of APMI. These facilities are charged on a cost recovery basis for time and material incurred at these sites.

- 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. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. APUC has an option to acquire APMI's interest in these royalties for an amount of \$0.6 million. APMI is also entitled to a development fee of up to \$0.4 million following commercial operation of the project and has agreed to permit the Board to determine whether it will retain this fee following commercial operation of the facility. APUC received and recognized \$0.2 million in other revenue related to this fee in the nine months ended September 30, 2010.
- The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.
- Under these arrangements, as at September 30, 2010 amount due from related parties was \$981 (December 31, 2009 - \$1,028) and amounts due to related parties was \$1,022 (December 31, 2009 - \$827).

Business associations with APMI and Senior Executives.

There are a number of continuing business relationships between APUC and one of Ian Robertson and Chris Jarratt ("Senior Executives"), APMI and related affiliates. These relationships include joint ownership of certain generating facility assets. The Board has initiated a process to review all of the remaining business associations with APMI in order to reduce, streamline and simplify these remaining relationships. All transactions associated with this process will only proceed if they are expected to be accretive to APUC.

The Board has formed a special committee and intends to engage independent consultants to assist with this process and expects to conclude this process over the next six months.

The co-owned assets and remaining business associations consist of the following:

i) Rattlebrook hydroelectric generating facility

Rattlebrook is a 4 MW hydroelectric generating station owned 45% by APUC and 41.25% by Senior Executives and the remaining percentage by third parties.

ii) St. Leon wind power generating facility

St. Leon is a 100 MW wind power generating facility which has issued Class B units to external parties including Senior Executives.

iii) Brampton Co-generation Inc.

BCI is an energy supply facility which sells steam produced from APCo's EFW facility. APMI maintains a carried 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 \$100 in relation to the development of this project. As of

September 30, 2010 this amount is accrued and included in accounts payable on the consolidated balance sheet.

iv) *Long Sault Rapids hydroelectric generating facility*

Long Sault is a hydroelectric generating facility. APUC acquired its interest in the facility by way of subscribing to two notes from the original developers and it has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. 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.

v) *Chartered aircraft*

APUC utilizes chartered aircraft owned by an affiliate of APMI. APUC entered into an agreement and remitted \$1.3 million to the affiliate as an advance against expense reimbursements. At September 30, 2010, \$0.6 million of the advance remained.

vi) *Office lease*

APUC has leased its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The lease expires in December 31, 2012. Based on a review of the real estate leasing market at the time, APUC believes the lease was on terms equivalent to fair market value for prime office space of similar size and quality.

vii) *Operations services*

Staff currently employed by APUC operate three hydroelectric generating facilities where Senior Executives hold an interest. Each facility is charged on a full cost recovery basis for these staff.

viii) *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 contingency fee. In 2008, APUC accrued U.S. \$0.6 million as an estimate of the final fee owed to APMI.

ix) *Clean Power Income Fund*

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund 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. As of September 30, 2010 this amount is accrued and included in accounts payable on the consolidated balance sheet.

x) *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. APUC has an option to acquire APMI's interest in these royalties for an amount of \$0.6 million. APMI is also entitled to a development fee of up to \$0.4 million following commercial operation of the project and has agreed to permit the Board to determine whether it will retain this fee following commercial operation of the facility.

xi) *Trafalgar*

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, Algonquin moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar had previously won a \$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 then reached 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 costs with the proceeds from the lawsuits being shared after reimbursement of legal costs. The Second Circuit Court of Appeals recently found in favour of APUC in the civil proceedings, however follow up proceedings are expected and the bankruptcy proceedings continue.

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 Water 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, any credit risk associated with a reliance on key customers, interest rate, liquidity and commodity price risk considerations. 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 Annual Information Form.

Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the

United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 45% of EBITDA and 60% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a \$0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in increased reported revenue from U.S. operations of approximately \$9.6 million and increased reported expenses from U.S. operations of approximately \$6.4 million or a net impact of \$3.2 million (\$0.034 per share) on an annual basis.

APUC previously managed this risk primarily through the use of forward contracts as it required U.S. dollar cash inflows to meet Canadian dollar cash outflows. As a result of the current business strategy and lower payout ratio, APUC has determined that the prior practice of hedging 100% of its U.S. currency exposure is no longer appropriate and is taking steps to eliminate its existing forward currency contract program. During the nine months ended September 30, 2010, APUC terminated forward contracts of \$11.7 million at a net cost of \$10. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes. For the three and nine months ended September 30, 2010, APUC realized cash gains of \$0.2 million and \$0.6 million respectively on managing its forward contracts.

The following chart sets out as at September 30, 2010 the amounts, hedge proceeds and average hedged rates over the term of the foreign exchange forward contracts outstanding. Contracts terminated subsequent to the quarter are omitted from this chart:

	Total	2010	2011	2012	2013
Total U.S. \$ Hedged	\$ 28,030	\$ -	\$ 16,700	\$ 10,580	\$ 750
Total Can. \$ Proceeds	\$ 28,479	-	16,856	10,820	803
Average Hedged Rate	\$ 1.016	n/a	\$ 1.009	\$ 1.023	\$ 1.070
Unrealized Gain (loss)	\$ (742)	n/a	(480)	(271)	9
Impact of a \$0.10 move in exchange rates	\$ 2,803	n/a	\$ 1,670	\$ 1,058	\$ 75

Based on the fair value of the forward contracts using the exchange rates as at September 30, 2010, the exercise of these forward contracts will result in the use of cash of \$0.5 million in fiscal 2011 and result in the use of cash of \$0.3 million for the remainder of the hedged period beyond 2011.

Assuming a decrease in the strength of the US dollar relative to the Canadian dollar of \$0.10 at September 30, 2010, with a corresponding increase in the forward yield curve, the fair value of the outstanding forward exchange contracts would increase by \$2.8 million, resulting in the generation of additional cash of \$1.7 million in fiscal 2011, and the generation of \$1.1 million in additional cash for the remainder of the hedged period beyond 2011.

Market price risk

The majority of APCo's electricity generating facilities sell their output pursuant to long term PPAs. However, certain of APCo's hydroelectric facilities in the New England and New York regions sell energy at current spot market rates. In this regard, each \$10.00 per MW-hr change in the market prices in the New England and New York regions would result in a change in revenue of \$1.0 million on an annualized basis.

Energy price risk

APCo's Energy Services Business provides the short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 150,000 MW-hrs on an annualized basis. While the Tinker Assets are expected to provide the majority of the energy required to service these customers, the Energy Services Business anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy. In the event that the Energy Services Business was required to purchase all of its energy requirements at ISO NE spot rates, each \$10.00 change per MW-hr in the market prices in ISO NE would result in a change in expense of \$1.5 million on an annualized basis.

This risk is mitigated though the use of short-term forward energy hedge contracts. APCo has committed to acquire approximately 15,000 MW-hrs of net energy over the next 5 months at an average rate of approximately \$75 per MW-hr. The mark-to-market value of these forward energy hedge contracts at September 30, 2010 was a net liability of U.S. \$0.9 million.

Interest rate risk

APUC and its subsidiaries have a number of project specific and other debt facilities that are subject to a variable interest rate. These facilities and the sensitivity to changes in the variable interest rates charged are discussed below:

- The Facilities had an outstanding balance drawn of CAD \$76.0 million and U.S. \$32.0 million as at September 30, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by CAD \$0.8 million and U.S. \$0.3 million annually. Algonquin has fixed for floating interest rate swaps in an amount of CAD \$100.0 million which fix the interest expense on CAD \$100.0 million of borrowings at approximately 4.125% for the remainder of 2010. This reduces volatility in the interest expense on this debt. The financial impact of any changes in interest rates are partially offset between the change in interest expense and the change in the underlying value of the interest rate swap. At September 30, 2010, the mark-to-market value of the interest rate swap was a net \$0.7 million liability (September 30, 2009 – \$3.9 million net liability).
- APCo's project debt at the St. Leon facility had a balance of \$69.2 million as at September 30, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by \$0.7 million annually. Although the

underlying debt with the project lenders carries variable rate of interest tied to the Canadian bank's prime rate, APCo has entered into a fixed for floating interest rate swap on this project specific debt until September 2015 which mirrors the underlying debt's interest and principal repayment schedule. This minimizes volatility in the interest expense on this debt. The financial impact of interest rate changes are effectively offset between the change in interest expense and the change in value of the interest rate swap. APCo has effectively fixed its interest expense on its senior debt facility at 5.47%. At September 30, 2010, the mark-to-market value of the interest rate swap was a net liability of \$7.0 million (September 30, 2009 – net liability of \$5.9 million).

- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. \$19.2 million as at September 30, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by U.S. \$0.2 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. APUC's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

APUC currently pays a dividend of \$0.24 per 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 their judgment, ensure APUC's long-term success. Based on the current level of dividends paid during the three and nine months ended September 30, 2010, cash provided by operating activities exceeded dividends declared by 1.1 times and 1.6 times respectively.

As at September 30, 2010, APUC had cash on hand of \$3.1 million and \$20.7 million available to be drawn on the Facilities. The Facilities mature on January 14, 2011 and therefore the Facilities are currently classified on the interim consolidated balance sheet as a current liability.

APUC expects to reduce its level of short term borrowings under the Facilities which mature on January 14, 2011 through obtaining appropriate long term permanent debt through refinancing certain project specific financings or additional medium to long term notes. See the Liquidity and Capital Reserves section for a more detailed discussion and chart of the funds available to APUC and its subsidiaries under the Facilities.

The Facilities and project specific debt total approximately \$256.5 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 favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment into the company may be negatively impacted. APUC attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

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 Water is not subject to any material commodity price risk. In this regard, a discussion of this risk is set out as follows:

- APCo's Sanger facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a \$1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately \$1.1 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of \$1.2 million or a net increase in operating profits of approximately \$0.1 million.
- APCo's Windsor Locks facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a \$1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately \$1.0 million on an annual basis.
- APCo's BCI facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a \$1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately \$0.3 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of \$0.4 million or a net increase in operating profits of approximately \$0.1 million.

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. In addition to risk disclosed herein, an assessment of APUC risks should be considered in conjunction with the risks disclosed in APUC's MD&A for the year ended December 31, 2009. The risks discussed below are not intended as a complete list of all

exposures that APUC and its subsidiaries may encounter. A further assessment of APUC's business risks is also set out in the most recent AIF.

Regulatory Risk

Liberty Water's facilities are subject to rate setting by State regulatory agencies. Liberty Water has five ongoing rate cases before regulatory bodies in Arizona and Texas in varying stages of completion. More details regarding the status of these proceedings are set out in Outlook – Liberty Water. The time between the incurrence of costs and the granting of the rates to recover those costs by utility commissions is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on water and wastewater utility operations.

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations. Based on its assessments, APUC's businesses do not have any significant retirement obligation liabilities and APUC has not recorded any liability in its financial statements.

Environmental Risks

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at September 30, 2010.

Critical Accounting Estimates

APUC prepared its interim Consolidated Financial Statements in accordance with Canadian GAAP. An understanding of APUC's accounting policies is necessary for a complete analysis of results, financial position, liquidity and trends. Refer to Note 1 to the interim Consolidated Financial Statements for additional information on accounting principles. The interim Consolidated Financial Statements are presented in Canadian dollars rounded to the nearest thousand, except per unit amounts and except where otherwise noted.

Additional disclosure of APUC's critical accounting estimates is also available in APUC's MD&A for the year ended December 31, 2009 available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Controls and Procedures

There were no changes made in the third quarter of 2010 to the internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the internal control over financial reporting.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended September 30, 2010.

Millions of dollars

(except per share amounts)

	4th Quarter	1st Quarter	2nd Quarter	3rd Quarter
	2009	2010	2010	2010
Revenue	\$ 43.4	\$ 45.9	\$ 42.7	\$ 45.4
Net earnings / (loss)	(1.4)	3.5	(2.2)	1.5
Net earnings / (loss) per share/trust unit	(0.03)	0.04	(0.02)	0.02
Total Assets	1,013.4	966.2	983.2	969.4
Long term debt*	439.9	434.0	446.7	452.8
Dividend/distribution per share/trust unit	0.06	0.06	0.06	0.06

	4th Quarter	1st Quarter	2nd Quarter	3rd Quarter
	2008	2009	2009	2009
Revenue	\$ 56.5	\$ 52.2	\$ 46.5	\$ 45.1
Net earnings / (loss)	(21.1)	4.2	15.3	13.1
Net earnings / (loss) per trust unit	(0.27)	0.05	0.20	0.17
Total Assets	978.5	974.2	952.4	925.7
Long term debt*	462.9	457.6	456.2	445.4
Distribution per trust unit	0.06	0.06	0.06	0.06

* Long term debt includes long term liabilities, the Facilities, convertible debentures and other long term obligations

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 \$42.7 million and \$56.5 million over the prior two year period. A number of factors impact quarterly results including seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the significant fluctuation in the strength of the Canadian dollar which has resulted in significant changes in reported revenue from U.S. operations.

Quarterly net earnings have fluctuated between net earnings of \$15.3 million and a net loss of \$21.1 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as future tax expense due to the enactment of Bill C-52 and mark-to-market gains and losses on financial instruments.

Changes in Accounting Policies

APUC's accounting policies are described in Note 1 to the interim Consolidated Financial Statements for the period ended September 30, 2010. There have been no changes to the critical accounting policies as disclosed in APUC's audited Consolidated Financial Statements for the period ended December 31, 2009 except as disclosed below.

Change in accounting estimates

As a result of the change in its corporate structure, APUC re-evaluated its exposure to currency exchange rate changes as determined by the underlying facts and circumstances of the economy in which the U.S. divisions operate. APUC concluded that the U.S. operations of the Renewable Energy and Thermal Energy divisions no longer should be classified as integrated foreign operations but rather self-sustaining operations. Consequently, these divisions are prospectively translated into Canadian dollars using the current rate method, effective January 1, 2010. The net exchange adjustment of \$37.6 million resulting from the current rate translation of non-monetary items principally property, plant and equipment and intangible assets as of the date of the change is included as a separate component of other comprehensive income with a corresponding reduction to the carrying amount of the non-monetary items.

Accounting Framework

In 2011, most publicly accountable enterprises in Canada will be required to change the accounting framework under which financial statements are prepared to International Financial Reporting Standards ("IFRS"). The adoption of IFRS is one of the alternatives available to APUC. As an entity with rate-regulated activities, APUC could also avail itself of the one-year deferral approved by the Accounting Standard Board of the Canadian Institute of Chartered Accountants in September 2010. Alternatively, as an existing SEC registrant, APUC could also choose to report its financial statements under US GAAP.

APUC evaluated the three options and assessed which of the three accounting frameworks would provide its shareholders and other interested readers of its financial statements the most useful basis for financial reporting. Considering the short-term nature of the CICA solution and the uncertainty around the eventual adoption of a rate-regulated accounting standard under IFRS, US GAAP financial statements represent the least disruptive accounting framework for readers of APUC's financial statements. This option would result in minimal changes having to be made to its financial statements as there are fewer differences between US GAAP and current Canadian GAAP. US GAAP also includes accounting standards for rate-regulated activities within the financial statements

As such, APUC has decided to adopt US GAAP effective January 1, 2011 for purposes of Canadian and US reporting requirements. US GAAP reporting is permitted by Canadian securities laws and the TSX for companies subject to reporting obligations under US securities laws.

Changeover to US Generally Accepted Accounting Standards –January 1, 2011

As an SEC registrant, APUC reconciles its financial statements from Canadian GAAP to US GAAP for purpose of annual reporting on Form 40-F with the SEC as a foreign private issuer. As a consequence, no significant impact of the transition to US GAAP is expected on APUC's internal controls, information technology systems and financial reporting expertise requirements. APUC has initiated discussions with the lenders of its Credit Facilities which are maturing on January 14, 2011. APUC expects to be able to negotiate any required amendments to covenants that may be impacted by the conversion to US GAAP.

Commencing in the first quarter of 2011, US GAAP will be applied retrospectively to all prior periods. In the 2011 financial statements, the cumulative impact of change to US GAAP will be reflected in the balance sheet as at January 1, 2010, which is the opening balance sheet of APUC's financial statements for the two year period ended December 31, 2011. The conversion to US GAAP results in the following differences to the balance sheet items at January 1, 2010:

	January 1, 2010 Canadian GAAP	January 1, 2010 US GAAP
Property, plant and equipment	\$ 749,350	\$ 749,350
Other assets – regulatory assets	1,713	1,713
Other assets – deferred transaction costs (a)	1,474	0
Deferred financing costs (c)	200	6,001
Long term liabilities	244,772	244,970
Convertible debentures (b), (c)	173,772	185,600
Future income tax liability	80,827	79,879
Derivative liabilities	9,695	9,695
Additional paid-in capital (d)	0	1,487
Shareholders' capital (b), (d)	787,037	785,827
Deficit	(344,676)	(352,219)

The key differences affecting the balance sheet items as at January 1, 2010 are described below. Many of those differences are limited to changes in classification within the financial statements. The following information should be read in conjunction with APUC's December 31, 2009 reconciliation with US GAAP which can be found on EDGAR.

- a) Business combination –deferred transaction costs
Under Canadian GAAP, APUC recorded \$1,474 in assets, deferred transaction costs in connection with future acquisitions. Under US GAAP, acquisition-related costs are expensed as incurred.

b) Convertible debentures

Similar to Canadian GAAP, under US GAAP the change in coupon rates and maturity terms of the convertible debentures under the CD Exchange Offer which took place in 2009 is considered to be a debt modification and not an extinguishment based on APUC's evaluation of the changes in cash flows and fair value of the conversion options under the terms of the revised debt agreements. The consolidated balance sheet of APUC under Canadian GAAP reflects the convertible debentures at their original carrying values, net of an allocation of transaction costs of approximately \$2,544 associated with the CD Exchange Offers. Under US GAAP these transaction costs of \$2,544 are expensed as incurred since the costs are paid to third parties and not the debtor.

Under Canadian GAAP, the fair value of the Series 3 convertible debentures was bifurcated into equity (the conversion option) and debt whereas under US GAAP, the convertible debentures do not have the features that would require bifurcation. Accordingly, an adjustment of \$4,275 reflects the reclassification of the value attributed to the equity components recorded under Canadian GAAP to convertible debentures under US GAAP.

c) Financing costs

APUC records financing costs as a reduction to long-term liabilities and convertible debentures under Canadian GAAP. Under US GAAP, such costs are presented in assets as deferred financing costs. Accordingly, the classification adjustment reflects a cumulative increase of \$197 in long-term liabilities and \$5,604 in convertible debentures with a corresponding increase in deferred financing costs of \$5,801.

d) Conversion option

The change in conversion price of the Series 1 and Series 2 convertible debentures under the CD Exchange Offer resulted in a combined fair value of the conversion feature of \$1,487. Under US GAAP, the fair value of the conversion feature is recorded as a discount on debt, with an offsetting entry to additional paid-in-capital. Under Canadian GAAP, the offsetting entry is recorded in equity. An adjustment of \$1,487 reflects the reclassification of conversion feature recorded as equity under Canadian GAAP to additional paid-in capital under US GAAP.

Net earnings prepared in accordance with US GAAP following the conversion are expected to differ from net earnings under Canadian GAAP in certain aspects. The key differences expected to impact net earnings in 2011 and/or its comparative period in 2010 are described below:

a) Business combination –deferred transaction costs

In 2010, APUC records deferred transaction costs in connection with future acquisitions in assets under Canadian GAAP. Under US GAAP, acquisition-related costs are expensed as incurred. Effective 2011, Canadian and US GAAP will be aligned on this particular matter.

b) Convertible debentures

Interest expense on the convertible debentures under US GAAP will be lower than under Canadian GAAP due to the following:

Canadian GAAP would have reflected the amortization of the CD Exchange Offer transaction costs of \$2,544 over the remaining term of the Series 1 and Series 2 convertible debenture while it has been expensed in 2009 under US GAAP.

Under Canadian GAAP, an amount of \$4,275 representing the accretion of the residual carrying value of the Series 3 convertible debentures to the face value of the convertible debentures over the life of the instrument is charged to operations. Under U.S. GAAP, no such accretion is required as the conversion feature is not required to be bifurcated.

Interim Consolidated Balance Sheets

(Unaudited) (thousands of Canadian dollars)

	September 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash	\$ 3,146	\$ 2,796
Short term investments	-	40,010
Accounts receivable	23,999	20,484
Prepaid expenses	3,422	4,674
Income tax receivable	576	1,143
Current portion of future tax asset	13,321	14,566
Current portion of notes receivable	539	521
	45,003	84,194
Long-term investments and notes receivable	31,305	24,029
Future non-current income tax asset	62,692	61,219
Property, plant and equipment (note 3)	743,586	749,350
Intangible assets (note 3)	77,607	85,929
Restricted cash	3,808	4,316
Deferred financing costs	159	200
Other assets (note 3)	5,269	4,176
	\$ 969,429	\$ 1,013,413
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 26,058	\$ 33,219
Dividends payable	5,702	1,857
Income taxes payable	787	5
Current portion of long-term liabilities (note 5)	112,428	3,360
Current portion of other long-term liabilities	1,071	1,025
Current portion of derivative liabilities (notes 3 and 13)	4,174	5,775
Current portion of deferred credits	10,398	10,500
Future income tax liability	356	913
	160,974	56,654
Long-term liabilities	144,058	241,412
Convertible debentures	171,596	173,257
Other long-term liabilities	28,212	25,228
Future income tax liability	79,533	79,914
Derivative liabilities (note 13)	5,224	3,920
Deferred credits (note 11)	35,319	39,379
Shareholders' equity:		
Shareholders' capital (note 6)	795,248	787,037
Deficit	(358,965)	(344,676)
Accumulated other comprehensive loss	(91,770)	(48,712)
	344,513	393,649
	\$ 969,429	\$ 1,013,413

See accompanying notes to interim consolidated financial statements

Interim Consolidated Statements of Operations

(Unaudited) (thousands of Canadian dollars, except per common share amounts)

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
	2010	2009	2010	2009
Revenue:				
Energy sales	\$ 30,411	\$ 30,139	\$ 98,674	\$ 100,013
Waste disposal fees	3,868	3,821	4,875	10,682
Water reclamation and distribution	10,248	10,222	28,002	29,826
Other revenue	916	928	2,457	3,303
	45,443	45,110	134,008	143,824
Expenses				
Operating	25,171	24,219	73,543	78,796
Amortization of property, plant and equipment	9,130	9,700	27,154	29,059
Amortization of intangible assets	2,623	1,813	7,519	5,474
Management costs (note 7)	-	213	-	639
Administrative expenses	3,855	3,250	9,760	8,181
(Gain) / loss on foreign exchange	(841)	313	(474)	(1,003)
	39,938	39,508	117,502	121,146
Earnings before undernoted	5,505	5,602	16,506	22,678
Interest expense	6,480	5,086	18,893	15,742
Interest, dividend income and other income	(1,349)	(2,848)	(3,709)	(5,133)
(Gain) / loss on derivative financial instruments (note 13)	805	(7,100)	2,945	(15,803)
	5,936	(4,862)	18,129	(5,194)
Earnings / (loss) from operations before income taxes and minority interest	(431)	10,464	(1,623)	27,872
Income tax expense (recovery)				
Current	220	167	655	631
Future (note 11)	(2,289)	(3,091)	(5,344)	(7,896)
	(2,069)	(2,924)	(4,689)	(7,265)
Minority interest in earnings of subsidiaries	105	310	315	2,514
Net earnings	\$ 1,533	\$ 13,078	\$ 2,751	\$ 32,623
Basic net earnings per share (note 8)	\$ 0.02	\$ 0.17	\$ 0.03	\$ 0.42
Diluted net earnings per share (note 8)	\$ 0.02	\$ 0.17	\$ 0.03	\$ 0.42

See accompanying notes to interim consolidated financial statements

Interim Consolidated Statements of Cash Flows

(Unaudited) (thousands of Canadian dollars)

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
	2010	2009	2010	2009
Cash provided by (used in):				
Operating Activities:				
Net earnings	\$ 1,533	\$ 13,078	\$ 2,751	\$ 32,623
Items not affecting cash:				
Amortization of property, plant and equipment	9,130	9,700	27,154	29,059
Amortization of intangible assets	2,623	1,813	7,519	5,474
Other amortization	752	256	2,113	734
Distributions received in excess of equity income	381	(154)	1,027	1,336
Future income taxes recovery	(2,289)	(3,091)	(5,344)	(7,896)
Gain on sale of land	-	(1,451)	-	(1,451)
Unrealized gain on derivative financial instruments	(1,059)	(8,545)	(3,629)	(20,218)
Stock option expense	34	-	34	-
Minority interest	105	310	315	2,514
Unrealized foreign exchange gain	(1,046)	(68)	(831)	(958)
	10,164	11,848	31,109	41,217
Changes in non-cash operating working capital (note 10)	(4,022)	2,540	(3,044)	(3,744)
	6,142	14,388	28,065	37,473
Financing Activities:				
Cash dividends / distributions (note 9)	(5,706)	(4,681)	(13,192)	(14,022)
Cash distributions to non-controlling interest (notes 7 and 9)	(105)	(200)	(318)	(670)
Trustee loans	-	9	-	15
Deferred financing costs	(62)	5	(153)	(47)
Increase in long-term liabilities	13,497	-	67,997	14,000
Decrease in long-term liabilities	(7,502)	(5,685)	(55,120)	(24,261)
Decrease (increase) in other long-term liabilities	(574)	(500)	(399)	126
	(452)	(11,052)	(1,185)	(24,859)
Investing Activities:				
Decrease in restricted cash	310	215	435	122
Decrease in short-term investment	-	-	40,010	-
Increase in other assets	(229)	(1,610)	(1,035)	(2,642)
Receipt of principal on notes receivable	105	94	304	351
Proceeds from liquidation of Highground assets (note 3(c))	-	-	170	302
Increase in long term investments and notes (note 4)	(2,094)	-	(8,659)	-
Proceeds from sale of land	-	2,502	-	2,502
Net additions to property, plant and equipment	(2,666)	(3,303)	(14,653)	(10,199)
Acquisitions of operating entities (note 3)	(364)	(113)	(43,094)	(860)
	(4,938)	(2,215)	(26,522)	(10,424)
Effect of exchange rate differences on cash	(2)	(308)	(8)	(402)
Increase in cash	750	813	350	1,788
Cash, beginning of the period	2,396	6,877	2,796	5,902
Cash, end of the period	\$ 3,146	\$ 7,690	\$ 3,146	\$ 7,690
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest expense	\$ 4,896	\$ 5,056	\$ 14,026	\$ 15,129
Cash paid during the period for income taxes	\$ (206)	\$ (121)	\$ (81)	\$ 816

See accompanying notes to interim consolidated financial statements

Interim Consolidated Statement of Deficit

(Unaudited) (thousands of Canadian dollars)

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
	2010	2009	2010	2009
Balance, beginning of period	\$ (354,744)	\$ (346,417)	\$ (344,676)	\$ (358,669)
Adjustments relating to adoption of EIC 173 without restatement of prior periods	-	-	-	2,048
	(354,744)	(346,417)	(344,676)	(356,621)
Net earnings	1,533	13,078	2,751	32,623
Dividends/Distributions (note 9)	(5,754)	(4,681)	(17,040)	(14,022)
Balance, end of period	\$ (358,965)	\$ (338,020)	\$ (358,965)	\$ (338,020)

See accompanying notes to consolidated financial statements

Interim Consolidated Statements of Comprehensive Income / (Loss) and Accumulated Other Comprehensive Income / (Loss)

(Unaudited) (thousands of Canadian dollars)

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
	2010	2009	2010	2009
Net earnings	\$ 1,533	\$ 13,078	\$ 2,751	\$ 32,623
Other comprehensive loss:				
Forward exchange contracts settled in the period	-	(279)	-	(1,692)
Translation of self sustaining foreign operations	(8,915)	(12,528)	(5,453)	(21,128)
Other comprehensive income (loss)	(8,915)	(12,807)	(5,453)	(22,820)
Total comprehensive income (loss)	\$ (7,382)	\$ 271	\$ (2,702)	\$ 9,803
Accumulated other comprehensive loss:				
Balance, beginning of the period	\$ (82,855)	\$ (31,455)	\$ (48,712)	\$ (21,442)
Translation of self sustaining foreign operations due to accounting change (note 2)	-	-	(37,605)	-
Other comprehensive income / (loss)	(8,915)	(12,807)	(5,453)	(22,820)
Balance, end of the period	\$ (91,770)	\$ (44,262)	\$ (91,770)	\$ (44,262)

See accompanying notes to interim consolidated financial statements

Notes to the Unaudited Interim Consolidated Financial Statements

Nine months ended September 30, 2010 and 2009 (in thousands of Canadian dollars except as noted and per share)

1. Basis of presentation:

These unaudited interim consolidated financial statements of Algonquin Power & Utilities Corp. ("APUC" or "the Company") should be read in conjunction with the audited consolidated financial statements of APUC for the year ended December 31, 2009. The notes presented in these unaudited interim consolidated financial statements include only significant changes and transactions occurring since APUC's last year end, and are not fully inclusive of all disclosures required by Canadian generally accepted accounting principles for annual financial statements.

APUC's operating results are subject to seasonal fluctuations that 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. Algonquin's water and wastewater utility assets revenues fluctuate depending on demand for water. During drier, hotter periods of the year, which occurs generally in the summer, demand for water is generally higher than during cooler, wetter periods of the year.

These unaudited interim consolidated financial statements follow the same accounting policies and methods of application as the 2009 annual financial statements, except as outlined below.

2. Change in accounting

As a result of the change in its corporate structure relating to conversion of the Company from an income trust to a corporation, the Company re-evaluated its exposure to currency exchange rate changes as determined by the underlying facts and circumstances of the economy in which the US divisions operate. The Company concluded that the US operations of the Renewable Energy and Thermal Energy divisions no longer should be classified as integrated foreign operations but rather as self-sustaining operations. Consequently, these divisions have been prospectively translated into Canadian dollars using the current rate method, effective January 1, 2010. The net exchange adjustment of \$37,605 resulting from the current rate translation of non-monetary items, principally property, plant and equipment and intangible assets, as of the date of the change is included as a separate component of other comprehensive income with a corresponding reduction to the carrying amount of the non-monetary items.

3. Acquisitions

a) Acquisition of electrical generation and regulated distribution utility

In 2009, APUC entered into an agreement to co-acquire an electrical generation and regulated distribution utility through a strategic partnership with Emera Inc. ("Emera"). APUC will own 50.001% and Emera will own 49.999% of the newly formed California Pacific Electric Company ("Calpeco"), which has agreed to acquire the California-based electricity distribution and related generation assets (the "California Utility") of NV Energy, Inc. for a purchase price of approximately US \$137 million, subject to certain working capital and other closing adjustments. APUC and Emera will together own and operate the California Utility through Calpeco. The California Utility currently provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. The transaction is subject to U.S. state and federal regulatory approval which is expected to occur in late 2010 or early 2011.

As an element of the strategic partnership announced on April 23, 2009, Emera has also agreed to a conditional treasury subscription of approximately 8.5 million shares of APUC at a price of \$3.25 per share. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of the California Utility. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost of acquisition of the California Utility.

During the three and nine months ended September 30, 2010, APUC has incurred costs of \$364 (2009 - \$113) and \$692 (2009 - \$810) related to the strategic partnership with Emera. These costs are recorded as deferred transaction costs and are included in other assets on the Consolidated Balance Sheet.

b) Acquisition of Hydroelectric Generation Assets ("Tinker Acquisition")

On January 12, 2010, APUC acquired certain electrical generating facility assets including 36.8MW of hydroelectric generating capacity located in New Brunswick and Maine. The acquisition consists of three hydroelectric

b) Acquisition of Hydroelectric Generation Assets (“Tinker Acquisition”) (continued)

generating stations, most notably the 34.5MW Tinker Hydroelectric station located on the Aroostook River near the Town of Perth-Andover, New Brunswick. The acquisition also includes five thermal generating stations and certain regulated New Brunswick Independent System Operator transmission lines located in proximity to the generating facilities. In connection with the Tinker Acquisition, on February 4, 2010, APUC also acquired a related energy services business (“Energy Services Business”).

The Energy Services Business retails the electricity generated by the Tinker facilities to commercial and industrial customers in northern Maine.

The total purchase price, including acquisition costs, was \$40,671. Acquisition costs of \$390 were paid in 2009 which were recorded as deferred transaction costs and included in other assets on the consolidated balance sheet at December 31, 2009.

The acquisition has been accounted for using the purchase method, with earnings from operations included since the date of acquisition.

The consideration paid by APUC has been preliminarily allocated to net assets acquired as follows:

Working capital (net of cash received of \$1)	\$	69
Property, plant and equipment		39,555
Intangible asset – energy sales contracts		4,421
Derivative liability – energy forward purchase contracts (note 11)		(3,374)
Total cash consideration	\$	40,671

The allocation of the purchase price has been based upon management’s preliminary estimates and certain assumptions with respect to the fair value increment associated with the assets acquired and liabilities assumed. The value assigned to property plant and equipment is subject to change due to finalization of tax values of the assets acquired at date of acquisition. The Company will continue to review information and perform further analysis prior to finalizing the allocation of the purchase price. The actual fair values of the assets and liabilities will be determined as of the date of acquisition and may differ from the amounts noted above in the preliminary purchase price allocation.

c) Acquisition of Water Utility System (“the Galveston Utility”)

On March 17, 2010 Liberty Water, a wholly owned subsidiary of APUC, acquired a water distribution and wastewater collection system located near Galveston, Texas for a total purchase price of \$2,038. The Galveston Utility provides water distribution and wastewater collection services to approximately 260 equivalent residential connections.

The acquisition has been accounted for using the purchase method, with earnings from operations included since the date of acquisition.

The consideration paid by APUC has been allocated to net assets acquired as follows:

Property, plant and equipment	\$	2,023
Intangible asset		15
Total cash consideration	\$	2,038

d) Highground Capital Corporation

In 2008, the Company entered into an agreement with Highground Capital Corporation (“Highground”), CJIG Management Inc. (“CJIG”), which is the manager of Highground and a related party of the Company controlled by the shareholders of Algonquin Power Management Inc (“APMI”). Under the agreement, CJIG acquired all of the issued and outstanding common shares of Highground and the Company issued trust units to the Highground shareholders and CJIG.

d) Highground Capital Corporation (continued)

The Company initially recorded the trust units issued at their fair value of \$7.69 per unit which, net of transaction costs of \$767, resulted in proceeds of the trust units being initially recorded at a value of \$26,203. By September 30, 2010, the Company has received consideration and issued equity as follows:

Consideration received:

Cash and assets received prior to December 31 2008	\$	26,203
Cash received in 2009		983
Cash received in 2010		170
	\$	27,356

In 2009, APUC's consideration received from the acquisition exceeded \$26,970, the minimum contemplated under the agreements, and, as a result APUC is entitled to 50% of any additional proceeds from the assets formerly owned by Highground. CJIG is entitled to the remaining 50% of any proceeds in excess of the minimum amount. During the three and nine months ended September 30, 2010, APUC received \$nil (2009 - \$nil) and \$170 (2009 - \$302) respectively from CJIG as APUC's share of the 50% of additional proceeds from the further liquidation of the assets held by Highground. This has been recorded as an increased amount assigned to the equity originally issued.

The remaining investments, formerly held by Highground, currently consist of two non-liquid debt assets having an approximate principal amount of \$2,246. APUC's 50% share of any additional proceeds from liquidation of the remaining Highground assets will be recorded as additional proceeds when received from CJIG.

4 Long term investments and notes receivable**a) Silverleaf Resorts Inc – Hill County**

On July 29, 2010, Liberty Water, a wholly owned subsidiary of APUC, made an investment in its Hill Country facility, a part of the Silverleaf Resorts Inc.'s ("SRI") facilities in Comal County, Texas. The investment of \$2,094 (U.S. \$2,021) was made under an agreement with SRI to increase the capacity of a wastewater treatment facility to support the growth of the utility. This investment has been recorded in long term investments and note receivable on the consolidated balance sheets.

b) Red Lily

On April 19, 2010, the Company entered into agreements to provide development, construction, operation and supervision services related to the construction, commissioning and operation of a 26.4 megawatt wind energy facility ("Red Lily I") in south-eastern Saskatchewan.

The equity in Red Lily I ("the Partnership") is owned by an independent investor. The Company's investment in Red Lily I is in the form of a participation in a senior debt facility to the Partnership and providing a subordinated debt facility. APUC's commitment under the senior debt facility is to advance up to \$13,000 of the Tranche 2 senior debt. The advance will be made to fund project costs required to develop and construct Red Lily I and is expected to be invested within the next six months. The senior debt will earn an interest rate of 6.31% and will mature five years following commissioning of the project. The senior debt is secured by substantially all the assets of the Partnership. On April 19, 2010, APUC advanced \$6,565 in subordinated debt to the Partnership. A second tranche of subordinated debt for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than \$17,000 will be advanced five years following commissioning of the project. The proceeds from this additional subordinated debt are required to be used to repay Tranche 2 of the Partnership's senior debt, including APUC's portion. The subordinated debt earns an interest rate of 12.5%, the principal matures 25 years following commissioning of the project but is repayable in whole or in part at any time after five years, without a pre-payment premium. The subordinated debt is secured by substantially all the assets of the Partnership but is subordinated to the senior lenders. Subsequent to the end of the quarter on October 28, 2010, APUC funded \$2.0 million of senior debt to the project.

b) Red Lily (continued)

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated debt of up to \$19,500, exercisable for a period of 90 days commencing five years following commissioning of the project.

5. Long-term liabilities

APUC's senior secured revolving operating and acquisition credit facilities (the "Facilities") mature on January 14, 2011. As of September 30, 2010, the outstanding amount due on the Facilities of \$108,928 has been recorded within the current portion of long-term liabilities on the consolidated balance sheet. The amount drawn at September 30, 2010 includes U.S. \$32,000 in U.S. funds.

6. Shareholders' capital

Shareholders' capital consists of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Balance of shares/units, beginning of period	\$ 789,496	\$ 726,127	\$ 781,274	\$ 721,953
Issued on conversion of Algonquin (AirSource)				
Power LP exchangeable units	-	424	-	4,296
Conversion of convertible debentures, net of costs	-	33	3,290	33
Amounts received in connection with the				
Highground transaction	-	-	170	302
Issuance pursuant to management internalization	-	-	4,762	-
Balance of shares/units, end of period	\$ 789,496	\$ 726,584	\$ 789,496	\$ 726,584
Trustee Loans	-	(202)	-	(202)
Stock options	34	-	34	-
Equity component of convertible debentures	5,718	479	5,718	479
Shareholders' capital	\$ 795,248	\$ 726,861	\$ 795,248	\$ 726,861

For the nine months ended September 30, 2010, \$3,491 principal amount of New Series 1 Debentures were converted at the option of holders at a price of \$4.08 for each share into 855,689 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling \$3,290 has been recorded as share capital. On September 30, 2010, there were 63,451 New Series 1 Debentures outstanding with a face value of \$63,451.

On June 29, 2010, the Company issued 1,180,180 shares valued at \$4,762 pursuant to the Management Internalization Agreement signed on December 21, 2009. The issuance of shares and final settlement was approved by the Company's shareholders at its annual general meeting held on June 23, 2010.

Number of common shares/units

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Common shares/units, beginning of period	95,099,989	77,981,962	93,064,120	77,574,372
Issued on conversion of Algonquin (AirSource)				
Power LP exchangeable units	-	44,608	-	452,198
Conversion of convertible debentures	-	3,000	855,689	3,000
Issued pursuant to management internalization	-	-	1,180,180	-
Common shares/units, end of period	95,099,989	78,029,570	95,099,989	78,029,570

6. Shareholders' capital (continued)

Stock Option Plan

On June 23, 2010, the Company's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Option holder may elect to surrender any portion of the vested options which is then exercisable in exchange for the In-the-Money Amount. In accordance with the Plan, the In-The-Money Amount represents the excess, if any, of the market price of a share at such time over the option price, in each case such In-the-Money amount being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

Effective August 12, 2010, the Board approved the grant of 1,102,041 options to senior executives of the Company. The options allow for the purchase of common shares at a price of \$4.05, the market price of the underlying common share at the date of grant. One-third of the options vests on each of January 1, 2011, 2012 and 2013. Options may be exercised up to eight years following the date of grant.

The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The following assumptions were used in determining the fair value of share options granted:

	2010
Risk-free Interest	2.9%
Expected Volatility	29.2%
Expected dividend yield	5.9%
Expected Life	8 years
Grant date fair value per option	\$ 0.61

The risk-free interest rate for periods within the expected life of the option is based on the zero-coupon Canada Government bond with a similar term at the grant date. Expected volatility is estimated based on the adjusted historic volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate is based upon historical rates in dividends of our shares.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the 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. For the three months ended September 30, 2010, the Company recorded \$34 in compensation expense. As at September 30, 2010, there was \$636 of total unrecognized compensation costs related to non-vested shares-based compensation arrangement granted under the Plan. The cost is expected to be recognized over a period of 2.2 years.

No share options were exercised in 2010 or exercisable at September 30, 2010. The intrinsic value of the 1,102,041 non-vested shares as at September 30, 2010 was \$584.

Shareholders' Rights Plan

On June 23, 2010, the Company's shareholders adopted a shareholders' rights plan (the "Rights Plan"). The Rights Plan has an initial term of three years. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events

6. Shareholders' capital (continued)

occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

7. Related party transactions

Up to December 21, 2009, Algonquin Power Management Inc. ("APMI") provided management services to the Fund including advice and consultation concerning business planning, support, guidance and policy making and general management services. On December 21, 2009, the Board of Directors (the "Board") reached an agreement ("Management Internalization Agreement") with APMI to internalize all management functions of the Fund which were provided by APMI. Therefore, for the three and nine months ended September 30, 2010, APMI was not paid a management fee. For the three and nine months ended September 30, 2009, APMI was paid on a cost recovery basis for all costs incurred and charged \$214 and \$639 respectively.

APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a net basis. Base lease costs for the three and nine months ended September 30, 2010 were \$82 (2009 - \$81) and \$245 (2009 - \$249) respectively.

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. During the three and nine months ended September 30, 2010, APUC incurred costs in connection with the use of the aircraft of \$162 (2009 - \$167) and \$370 (2009 - \$307) respectively and amortization expense related to the advance against expense reimbursements of \$36 (2009 - \$45) and \$99 (2009 - \$118) respectively.

Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), an indirect subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing June 17, 2008 growing to a maximum of 10% by year 15. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related party holders of the Class B units are entitled to cash distributions of \$63 (2009 - \$64) and \$189 (2009 - \$221) for the three and nine months ended September 30, 2010 respectively.

APMI is entitled to 50% of the cash flow above a 15% return on investment for the BCI project pursuant to its project management contract. During the three and nine months ended September 30, 2010 and 2009, no amounts were paid under this agreement. In 2008, APMI earned a construction supervision fee of \$100 in relation to the development of this project. As of September 30, 2010 this amount is accrued and included in accounts payable on the consolidated balance sheet.

A member of the Board of Directors of APUC is an executive at Emera Inc ("Emera"). A contract with a subsidiary of Emera to purchase energy on Independent System Operator New England ("ISO NE") and provide scheduling services on ISO NE was included as part of the acquisition of the Energy Services Business associated with the Tinker Acquisition. The contract expired in the three months ended March 31, 2010 and was not renewed. As a result of this contract, during the three months ended March 31, 2010 a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of the Energy Services Business. In this capacity, APUC paid a subsidiary of Emera an amount of \$1,368 (2009 - \$nil) which was included as an operating expense on the interim consolidated statement of operations.

During the period ended June 30, 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During the three and nine months ended September 30, 2010 APUC paid \$71 (2009 - \$nil) and \$132 (2009 - \$nil) in relation to this contract. In the same period, APUC issued a letter of credit to a subsidiary of Emera in an amount of U.S. \$500 in conjunction with this contract.

APUC has operation and maintenance service agreements with three hydroelectric generating facilities owned by

7. Related party transactions (continued)

affiliates of APML. As a result of these agreements, APUC employees operate these hydroelectric generating facilities owned by affiliates of APML. These facilities are charged on a cost recovery basis for time and material incurred at these sites.

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

Under these arrangements, as at September 30, 2010 amount due from related parties was \$981 (December 31, 2009 - \$1,028) and amounts due to related parties was \$1,022 (December 31, 2009 - \$827).

8. Basic and diluted net earnings per share/unit

Basic and diluted earnings per share/unit have been calculated on the basis of the weighted average number of shares outstanding during the period. The weighted average number of shares/units outstanding during the period are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Weighted average common shares/units – basic	95,099,989	78,002,990	94,063,029	77,878,983
Trust units issuable on conversion of exchangeable units	-	1,605,598	-	1,732,044
Weighted average shares/units – diluted	95,099,989	79,608,588	94,063,029	79,611,027

Units issuable on conversion of exchangeable units are calculated at the end of the period based on the weighted average exchangeable units outstanding during the period and applying the rate of exchange.

Shares/units potentially issuable on the conversion of the convertible debentures are anti-dilutive and are not included in the calculation of diluted weighted average shares/units for the three and nine months ended September 30, 2010 and 2009. At September 30, 2010, the Company had 40,605,862 shares potentially issuable upon conversion of the convertible debentures. Options to issue 1,102,041 common shares at \$4.05 per share were outstanding during a portion of the third quarter of 2010 but were not included in the computation of diluted earnings per share because they are anti-dilutive.

9. Cash distributions and dividends

All cash distributions and dividends of APUC are made on a discretionary basis as determined by the Board. Dividends are declared to shareholders of record on the last day of each quarter and are paid 15 days after declaration.

For the three and nine month periods ended September 30, 2010, APUC declared cash dividends to shareholders totaling \$5,754 (2009 - \$4,681) and \$17,040 (2009 - \$14,022) respectively or \$0.06 per share (2009 - \$0.06 per unit) and \$0.18 per share (2009 - \$0.18 per unit) respectively.

At December 31, 2009 all the outstanding Algonquin (AirSource) Power LP exchangeable units were exchanged for APUC shares and no longer exist. Total distributions to the Unitholders of the Algonquin (AirSource) Power LP exchangeable units for the three and nine months ended September 30, 2010 were \$nil. Total distributions to the Unitholders of the Algonquin (AirSource) Power LP exchangeable units for the three and nine months ended September 30, 2009 were \$94 and \$302 respectively and were recorded as a reduction in non-controlling interest on the unaudited consolidated balance sheet.

10. Non cash operating working capital

The change in non cash operating working capital is comprised of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Accounts receivable	\$ (286)	\$ 2,390	\$ (3,246)	\$ 2,146
Income tax receivable	(231)	110	567	266
Prepaid expenses	(309)	271	1,252	(531)
Accounts payable and accrued liabilities	(3,665)	(410)	(2,399)	(5,390)
Current income tax liability	469	179	782	(235)
Change in non cash working capital	\$ (4,022)	\$ 2,540	\$ (3,044)	\$ (3,744)

11. Deferred credits

Included in future income tax recoveries for the three and nine months ended September 30, 2010 are \$1,432 (2009 - \$nil) and \$4,162 (2009 - \$nil) respectively related to the recognition of deferred credits from the utilization of future income tax assets recognized at the time of the Unit Exchange Offer.

12. Segmented Information

APUC has two broad operating segments: Algonquin Power which owns or has interest in 48 renewable energy facilities and 14 high efficiency thermal energy facilities representing more than 490 MW of installed electrical generation capacity; and Liberty Water which owns and operates 19 utilities in the United States of America providing water or wastewater services in the states of Arizona, Texas, Missouri and Illinois.

Within Algonquin Power there are three divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. 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 Water provides transportation and delivery of water and wastewater in its service areas.

12. Segmented Information (continued)

The operations and assets for these segments are as follows:

Geographic Segments

Algonquin and its subsidiaries operate in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Revenue				
Canada	\$ 18,372	\$ 19,638	\$ 52,324	\$ 61,656
United States	27,071	25,472	81,684	82,168
	\$ 45,443	\$ 45,110	\$ 134,008	\$ 143,824
			September 30, 2010	September 30, 2009
Property, plant and equipment				
Canada			\$ 469,140	\$ 449,244
United States			\$ 274,446	312,128
			\$ 743,586	\$ 761,372
Intangible assets				
Canada			\$ 44,468	\$ 49,085
United States			\$ 33,139	\$ 39,143
			\$ 77,607	\$ 88,228
Other assets				
Canada			\$ 860	\$ 3,415
United States			\$ 4,409	\$ 1,642
			\$ 5,269	\$ 5,057

Revenues are attributable to the two countries based on the location of the underlying generating and utility facilities.

Reporting segments

APUC's reportable segments are Algonquin Power - Renewable Energy, Algonquin Power - Thermal Energy and Liberty Water. The development activities are reported under Renewable Energy or Thermal Energy as appropriate. For purposes of evaluating divisional performance, the Company allocates the realized portion of the gain 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. Interest expense is allocated to the divisions based on the project level debt related to the facilities in each division. Interest expense on the revolving credit facility is allocated between the reporting segments based on a percentage of the reporting segments share of the total property, plant and equipment and intangible assets. 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.

12. Segmented Information (continued)

The operations and assets for these segments are as follows:

Three months ended September 30, 2010

	Power Generation & Development			Liberty Water	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	16,057	14,354	30,411	-	-	30,411
Waste disposal fees	-	3,868	3,868	-	-	3,868
Water reclamation and distribution	-	-	-	10,248	-	10,248
Other revenue	562	354	916	-	-	916
Total revenue	16,619	18,576	35,195	10,248	-	45,443
Operating expenses	7,863	11,387	19,250	5,921	-	25,171
	8,756	7,189	15,945	4,327	-	20,272
Other administration costs	(1,432)	(666)	(2,098)	189	(1,946)	(3,855)
Foreign exchange gain	-	-	-	-	841	841
Interest expense	(1,865)	(215)	(2,080)	(428)	(3,972)	(6,480)
Interest, dividend and other income	230	125	355	57	937	1,349
Gain / (loss) on derivative financial instruments	(2,264)	-	(2,264)	-	1,459	(805)
Amortization of property, plant and equipment	(5,848)	(1,495)	(7,343)	(1,787)	-	(9,130)
Amortization of intangible assets	(1,756)	(695)	(2,451)	(172)	-	(2,623)
Net earnings / (loss) before income taxes and minority interest	(4,179)	4,243	64	2,186	(2,681)	(431)
Property, plant and equipment	395,527	178,502	574,029	169,313	244	743,586
Intangible assets	30,096	24,038	54,134	23,473	-	77,607
Total assets	453,336	223,102	676,438	206,972	86,019	969,429
Capital expenditures	409	1,231	1,640	1,024	2	2,666
Acquisition of operating entities	-	-	-	-	364	364

12. Segmented Information (continued)

Nine months ended September 30, 2010

	Power Generation & Development			Liberty Water	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	58,250	40,424	98,674	-	-	98,674
Waste disposal fees	-	4,875	4,875	-	-	4,875
Water reclamation and distribution	-	-	-	28,002	-	28,002
Other revenue	1,559	898	2,457	-	-	2,457
Total revenue	59,809	46,197	106,006	28,002	-	134,008
Operating expenses	22,037	34,677	56,714	16,829	-	73,543
	37,772	11,520	49,292	11,173	-	60,465
Other administration costs	(3,262)	(1,516)	(4,778)	(1,075)	(3,907)	(9,760)
Foreign exchange gain	-	-	-	-	474	474
Interest expense	(5,374)	(667)	(6,041)	(1,309)	(11,543)	(18,893)
Interest, dividend and other income	632	395	1,027	68	2,614	3,709
Gain / (loss) on derivative financial instruments	(4,532)	-	(4,532)	-	1,587	(2,945)
Amortization of property, plant and equipment	(16,101)	(5,739)	(21,840)	(5,314)	-	(27,154)
Amortization of intangible assets	(4,927)	(2,084)	(7,011)	(508)	-	(7,519)
Net earnings / (loss) before income taxes and minority interest	4,208	1,909	6,117	3,035	(10,775)	(1,623)
Property, plant and equipment	395,527	178,502	574,029	169,313	244	743,586
Intangible assets	30,096	24,038	54,134	23,473	-	77,607
Total assets	453,336	223,102	676,438	206,972	86,019	969,429
Capital expenditures	1,352	11,162	12,514	2,060	79	14,653
Acquisition of operating entities	40,281	-	40,281	2,121	692	43,094

12. Segmented Information (continued)

Three months ended September 30, 2009

	Power Generation & Development			Liberty Water	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	\$ 15,198	\$ 14,941	\$ 30,139	\$ -	\$ -	\$ 30,139
Waste disposal fees	-	3,821	3,821	-	-	3,821
Water reclamation and distribution	-	-	-	10,222	-	10,222
Other revenue	-	928	928	-	-	928
Total revenue	15,198	19,690	34,888	10,222	-	45,110
Operating expenses	4,932	13,102	18,034	6,185	-	24,219
	10,266	6,588	16,854	4,037	-	20,891
Other administration costs	(2,079)	(986)	(3,065)	(398)	-	(3,463)
Foreign exchange gain	-	-	-	-	(313)	(313)
Interest expense	(1,763)	(258)	(2,021)	(452)	(2,613)	(5,086)
Interest, dividend and other income	241	425	666	1,448	734	2,848
Gain / (loss) on derivative financial instruments	(591)	(147)	(738)	161	7,677	7,100
Amortization of property, plant and equipment	(4,190)	(3,277)	(7,467)	(2,233)	-	(9,700)
Amortization of intangible assets	(658)	(981)	(1,639)	(174)	-	(1,813)
Net earnings before income taxes and minority interest	1,226	1,364	2,590	2,389	5,485	10,464
Property, plant and equipment	\$ 400,909	\$ 183,573	\$ 584,482	\$ 176,890	\$ -	\$ 761,372
Intangible assets	31,280	31,421	62,701	25,527	-	88,228
Total assets	450,228	240,469	690,697	213,676	21,329	925,702
Capital expenditures	129	883	1,012	2,283	8	3,303
Acquisition of operating entities	-	-	-	-	113	113

12. Segmented Information (continued)

Nine months ended September 30, 2009

	Power Generation & Development			Liberty	Corporate	Total
	Renewable Energy	Thermal Energy	Total	Water		
Revenue						
Energy sales	\$ 51,623	\$ 48,390	\$ 100,013	\$ -	\$ -	\$ 100,013
Waste disposal fees	-	10,682	10,682	-	-	10,682
Water reclamation and distribution	-	-	-	29,826	-	29,826
Other revenue	-	3,303	3,303	-	-	3,303
Total revenue	51,623	62,375	113,998	29,826	-	143,824
Operating expenses	15,660	44,954	60,614	18,182	-	78,796
	35,963	17,421	53,384	11,644	-	65,028
Other administration costs	(4,984)	(2,520)	(7,504)	(1,316)	-	(8,820)
Foreign exchange gain	-	-	-	-	1,003	1,003
Interest expense	(5,530)	(870)	(6,400)	(1,573)	(7,769)	(15,742)
Interest, dividend and other income	793	681	1,474	1,411	2,248	5,133
Gain / (loss) on derivative financial instruments	2,456	(811)	1,645	316	13,842	15,803
Amortization of property, plant and equipment	(12,564)	(9,875)	(22,439)	(6,620)	-	(29,059)
Amortization of intangible assets	(1,975)	(2,933)	(4,908)	(566)	-	(5,474)
Net earnings before income taxes and minority interest	14,159	1,093	15,252	3,296	9,324	27,872
Property, plant and equipment	\$ 400,909	\$ 183,573	\$ 584,482	\$ 176,890	\$ -	\$ 761,372
Intangible assets	31,280	31,421	62,701	25,527	-	88,228
Total assets	450,228	240,469	690,697	213,676	21,329	925,702
Capital expenditures	634	2,857	3,491	6,601	107	10,199
Acquisition of operating entities	-	-	-	-	860	860

13. Derivative instruments

As of September 30, 2010, the fair value of derivative liabilities is as follows:

	September 30, 2010	December 31, 2009
Derivative liabilities:		
Interest Rate SWAP – St Leon	\$ 7,045	\$ 4,966
Interest Rate SWAP – revolving credit facility	727	3,260
Foreign exchange forward contracts	742	1,469
Energy forward purchase contracts	884	-
	\$ 9,398	\$ 9,695
Less: current portion	(4,174)	(5,775)
Long term derivative liabilities	\$ 5,224	\$ 3,920

Gain and loss on derivative financial instruments consist of the following:

	Three months ended September 30, 2010		Three months ended September 30, 2009		Nine months ended September 30, 2010		Nine months ended September 30, 2009	
Unrealized loss / (gain) on derivative financial instruments:								
Foreign exchange contracts	\$	(870)	\$	(7,696)	\$	(727)	\$	(14,421)
Interest rate swaps		345		(849)		(454)		(5,797)
Energy forward purchase contracts		(534)		-		(2,448)		-
Total unrealized loss / (gain) on derivative financial instruments	\$	(1,059)	\$	(8,545)	\$	(3,629)	\$	(20,218)
Realized loss/(gain) on derivative financial instruments:								
Foreign exchange contracts	\$	(167)	\$	(77)	\$	(592)	\$	431
Interest rate swaps		1,453		1,522		4,635		3,984
Energy forward purchase contracts		578		-		2,531		-
Total realized loss/(gain) on derivative financial instruments	\$	1,864	\$	1,445	\$	6,574	\$	4,415
Loss / (gain) on derivative financial instruments	\$	805	\$	(7,100)	\$	2,945	\$	(15,803)

a) Foreign Currency Risk

The Company uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from operations. Algonquin only enters into foreign exchange forward contracts with major Canadian financial institutions, thus reducing credit risk on these forward contracts. As at September 30, 2010, Algonquin had a notional amount of U.S. \$28,030 in outstanding foreign exchange forward contracts carrying an average rate of \$1.016. At September 30, 2010, the fair value of the foreign exchange forward contracts was a \$742 liability.

b) Interest Rate Risk

The Company is exposed to interest rate fluctuations related to certain of its debt obligations, including certain project specific debt and its revolving credit facility.

APUC's project debt at the St. Leon facility has a balance of \$69,175 as at September 30, 2010. The Company has entered into a fixed for floating interest rate swap related to this debt covering the period to September 2015. At September 30, 2010, the fair value of the interest rate swap was a \$7,045 liability.

APUC senior revolving credit facility has a balance of \$108,928 as at September 30, 2010. The Company has entered into a fixed for floating interest rate swap related to \$100,000 of this debt covering the period to December 2010. At September 30, 2010, the fair value of this interest rate swap was a \$727 liability.

13. Derivative instruments (continued):**c) Energy Price Risk**

APUC provides the short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 150,000 MW-hrs on an annualized basis. While the Tinker Assets are expected to provide the majority 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 forward energy hedge contracts. APUC has committed to acquire approximately 25,000 MW-hrs of energy over the next 5 months at an average rate of approximately \$75 per MW-hr. The mark to market value of these forward energy hedge contracts at September 30, 2010 was a net liability of \$884.

14. Comparative figures

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

Notes

Notes

Notes

Directors

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

Algonquin Power & Utilities Corp.

Ian Robertson, Chief Executive Officer
Chris Jarratt, Vice Chairman
David Bronicheski, Chief Financial Officer

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