2010 Q2

Algonquin Power & Utilities Corp.

Management's Discussion and Analysis

(All figures are in thousands of Canadian dollars, except per trust unit 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 six months ended June 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 six months ended June 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 August 12, 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 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 June 30, 2010, APCo owns 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 212 MW. APCo also owns a 99 MW wind powered generating station in Manitoba and 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 14 thermal energy facilities operate under PPAs and have an average remaining contract life of 7 years with a combined generating capacity of 436 MW.

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.

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 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 Electrical Utilities: In 2009, APUC announced plans to co-acquire an electrical generation and regulated distribution utility through a strategic partnership with Emera Inc. ("Emera"). The utility is the California-based electricity distribution and related generation assets of NV Energy, Inc, serving approximately 50,000 customers. Through its wholly owned subsidiary, Liberty Electric Co., APUC is pursuing further investment in electric distribution utilities and electric transmission facilities, sharing certain common infrastructure between utilities to support best-in-class customer care for its subsidiary utility ratepayers.

Regulated Water Utilities: Liberty Water is committed to being the 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 it 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.

Corporatization and Resolution of Business Associations with APMI and Senior Executives

Beginning in 2008, the Board of Trustees of Algonquin initiated a process to convert Algonquin Power Income Fund from an income trust to a full corporate business structure. The process involves three steps:

1 ***Convert to a corporate entity.***
This step was completed through a unit exchange transaction with a corporate entity in October, 2009.

2 ***Internalize management.***
On December 21, 2009, the Board of Directors of APUC (the "Board") reached an agreement with the shareholders of the Algonquin Power Management Inc., the former manager of APCo, (the "Manager" or "APMI") to internalize all management functions of APCo which were provided by the Manager. At its annual and special meeting (the "Meeting") held on June 23, 2010, 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 (the "Shares") which represent 1,158,748 Shares issued as per the agreement and 21,432 Shares representing dividends earned on the Shares following the date the agreement was reached.

These Shares are subject to certain restrictions. These restrictions include a provision that a shareholder of the Manager is prevented from selling the Shares for a period of five years, until December 20, 2014, while that person works for APUC and a provision that a shareholder of the Manager is prevented from selling the Shares for a period of six months after that person ceases to work for APUC. In either instance, the individual may sell up to 25% of the Shares in any calendar quarter.

The expense has been measured at $4,763, using a price for each share of $4.03, the adjusted closing market price on December 21, 2009, the date the agreement in principle was ratified.

3. ***Business associations with APMI and Senior Executives.***
As part of APUC's continuous disclosures, there a number of continuing business relationships between APUC and one or any of Ian Robertson, David Kerr 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 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")*
BCI is an energy supply facility which sells steam produced from APCo's Energy-From-Waste ("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.

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 December 31, 2009 $0.7 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.

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 $0.7 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.

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, the foreclosure on the assets and in the bankruptcy. 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 matters remain before the courts.

Corporate Governance – Expanded Board
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.

2010 Six Month results from operations
Key Selected Six Month Financial Information

	Six months ended June 30	
	2010	**2009**
Revenue	**$ 88,563**	$ 98,713
Adjusted EBITDA [2]	**$ 36,647**	$ 41,067
Cash provided by Operating Activities	**21,921**	23,083
Net earnings	**1,215**	19,545
Adjusted net earnings [3]	**2,851**	11,758
Dividend/distributions to Shareholders/Unitholders [1]	**11,283**	9,549

	Six months ended June 30			
		2010		**2009**
Per share/trust unit				
Net earnings	**$**	**0.01**	$	0.25
Adjusted net earnings [3]	**$**	**0.03**	$	0.15
Diluted net earnings	**$**	**0.01**	$	0.25
Cash provided by Operating Activities	**$**	**0.23**	$	0.29
Dividends/distributions to Shareholders/Unitholders	**$**	**0.12**	$	0.12
Total Assets		**983,158**		952,357
Long Term Debt [4]		**248,946**		286,838

1 Includes dividends/distributions to APUC shareholders/unitholders and Airsource units exchangeable into Algonquin 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 six months ended June 30, 2010, APUC reported total revenue of $88.6 million as compared to $98.7 million during the same period in 2009, a decrease of $10.2 million or 10.3%. The decrease in APUC revenue in the six months ended June 30, 2010 was primarily the result of a decrease of $5.6 million due to reduced average hydrology and wind resources in the Renewable Energy division, a decrease of $2.9 million primarily due to the expiry of the PPA with Connecticut Light & Power ("CL&P") in April 2010 and the change in operating model at the Windsor Locks facility in the Thermal Energy division and $5.9 million in lower waste disposal revenue at the EFW facility as a result of the unplanned outage, as compared to the same period in 2009. The above factors were partially offset by increases in revenue of $0.6 million in Liberty Water, $2.1 million resulting from increased weighted average energy rates in the Renewable Energy division (excluding the Maritime region) and revenue of $10.1 million generated by the Maritime region in the APCo Renewable Energy division, as compared to the same period in 2009. APUC generated revenues of approximately $1.0 million from development, construction supervision fees related to the commencement of construction of the Red Lily I wind project.

APUC reported decreased revenue of $7.2 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009. A more detailed analysis of these factors is presented within the business unit analysis.

For the six months ended June 30, 2010, APUC experienced an average U.S. exchange rate of approximately $1.035 as compared to $1.206 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 six months ended June 30, 2010 totalled $36.6 million as compared to $41.1 million during the same period in 2009, a decrease of $4.4 million or 10.8%. 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 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 six months ended June 30, 2010, net earnings totalled $1.2 million as compared to $19.5 million during the same period in 2009. Net earnings per share totalled $0.01 for the six months ended June 30, 2010, as compared to net earnings per trust unit of $0.25 during the same period in 2009.

Net earnings for the six months ended June 30, 2010 decreased by $3.9 million due to lower earnings from operating facilities, $1.8 million due to increased interest expense, $1.7 million related to lower recoveries of future income tax expense primarily due to the reasons discussed in *Corporate Expenses – Income Taxes*, $1.7 million due to non-cash losses resulting from the stronger Canadian dollar and $0.5 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 $2.0 million resulting from reduced minority interest expense at the St. Leon facility primarily due to the lower wind resource experienced in the six months ended June 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 $9.1 million in the six months ended June 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 $1.7 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:

		Six months ended June 30	
	2010	**2009**	**Change**
Foreign Exchange Contracts:			
Change in unrealized mark to market loss/(gain) on derivative financial instruments	**$ 143**	$ (6,726)	**$ 6,869**
Realized loss/(gain) on derivative financial instruments	**(425)**	509	**$ (934)**
	$ (282)	$ (6,217)	**$ 5,935**
Interest Rate Swap Contracts:			
Change in unrealized mark to market gain on derivative financial instruments	**$ (799)**	$ (4,948)	**$ 4,149**
Realized loss on derivative financial instruments	**3,182**	2,462	**$ 720**
	$ 2,383	$ (2,486)	**$ 4,869**
Energy Forward Purchase Contracts:			
Change in unrealized mark to market gain on derivative financial instruments	**$ (1,914)**	-	**$ (1,914)**
Realized loss on derivative financial instruments	**1,953**	-	**$ 1,953**
	$ 39	$ -	**$ 39**
Derivative Financial Instruments Total:			
Change in unrealized mark to market loss/(gain) on derivative financial instruments	**$ (2,570)**	$ (11,674)	**$ 9,104**
Realized loss on derivative financial instruments	**4,710**	2,971	**$ 1,739**
Total loss/(gain) on derivative financial instruments	**$ 2,140**	$ (8,703)	**$ 10,843**

During the six months ended June 30, 2010, cash provided by operating activities totalled $21.9 million or $0.23 per share as compared to cash provided by operating activities of $23.1 million, or $0.29 per trust unit during the same period in 2009. Cash provided by operating activities exceeded dividends by 1.9 times during the six months ended June 30, 2010 as compared to 2.4 times distributions during the same period in 2009. The change in cash provided by operating activities after changes in working capital in the six months ended June 30, 2010, is primarily due to increased realized losses from derivative instruments and decreased cash flow from operating facilities, partially offset by improved cash from working capital and increased interest, dividend and other income as compared to the same period in 2009.

2010 Second quarter results from operations
Key Selected Second Quarter Financial Information

	Three months ended June 30			
		2010		**2009**
Revenue	**$**	**42,676**	$	46,549
Adjusted EBITDA [2]	**$**	**18,711**	$	19,952
Cash provided by Operating Activities		**12,773**		9,382
Net earnings (loss)		**(2,236)**		15,302
Adjusted net earnings (loss) [3]		**(145)**		3,849
Dividend/distributions to Shareholders/Unitholders [1]		**5,686**		4,775
Per share/trust unit				
Net earnings (loss)	**$**	**(0.02)**	$	0.20
Adjusted net earnings (loss) [3]	**$**	**(0.00)**	$	0.05
Diluted net earnings	**$**	**(0.02)**	$	0.20
Cash provided by Operating Activities	**$**	**0.14**	$	0.12
Dividends/distributions to Shareholders/Unitholders	**$**	**0.06**	$	0.06
Total Assets		**983,158**		952,357
Long Term Debt[4]		**248,946**		286,838

1 Includes dividends/distributions to APUC shareholders/unitholders and Airsource units exchangeable into Algonquin 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 June 30, 2010, APUC reported total revenue of $42.7 million as compared to $46.5 million during the same period in 2009, a decrease of $3.9 million or 8.3%. The decrease in APUC revenue in the three months ended June 30, 2010 was primarily the result of a net decrease of $1.3 million at the Windsor Locks facility in the Thermal Energy division primarily due to the expiry of the PPA with CL&P and the change in the facility's operating model, partially offset by increased energy rates experienced by the facility, $3.1 million in lower waste disposal revenue at the EFW facility as a result of the unplanned outage and a $2.6 million decrease due to lower average hydrology and wind resources in the Renewable Energy division, as compared to the same period in 2009. These factors were partially offset by an increase of $0.5 million at Liberty Water, $0.6 million resulting from increased weighted average energy rates in the Renewable Energy division (excluding the Maritime region) and revenue of $4.6 million generated by the Maritime region in the Renewable Energy division, as compared to the same period in 2009. APUC generated revenues of approximately $1.0 million from development, construction supervision fees related to the commencement of construction of the Red Lily I wind project. In addition, APUC reported decreased revenue of $2.7 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009. A more detailed analysis of these factors is presented within the business unit analysis.

For the three months ended June 30, 2010, APUC experienced an average U.S. exchange rate of approximately $1.028 as compared to $1.167 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 June 30, 2010 totalled $18.7 million as compared to $20.0 million during the same period in 2009, a decrease of $1.2 million or 6.2%. 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 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 three months ended June 30, 2010, net loss totalled $2.2 million as compared to net earnings $15.3 million during the same period in 2009. Net loss per share totalled $0.02 for the three months ended June 30, 2010, as compared to net earnings per trust unit of $0.20 during the same period in 2009.

Net earnings for the three months ended June 30, 2010 decreased by $1.2 million due to lower earnings from operating facilities, $1.0 million due to increased interest expense, $2.3 million due to non-cash losses resulting from the stronger Canadian dollar, and $0.2 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, $0.2 million in increased interest, dividend and other income, $1.1 million related to increased recoveries of future income tax expense primarily due to the reasons discussed in Corporate Expenses – Income Taxes, and $1.5 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 $15.2 million in the three months ended

June 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 June 30		
	2010	**2009**	**Change**
Foreign Exchange Contracts:			
Change in unrealized mark to market loss/(gain) on derivative financial instruments	**$ 1,226**	$ (9,042)	**$ 10,268**
Realized loss/(gain) on derivative financial instruments	**(293)**	(2)	**$ (291)**
	$ 933	$ (9,044)	**$ 9,977**
Interest Rate Swap Contracts:			
Change in unrealized mark to market gain on derivative financial instruments	**$ 488**	$ (4,550)	**$ 5,038**
Realized loss on derivative financial instruments	1,586	1,393	$ 193
	$ 2,074	$ (3,157)	**$ 5,231**
Energy Forward Purchase Contracts:			
Change in unrealized mark to market gain on derivative financial instruments	**$ (80)**	-	**$ (80)**
Realized loss on derivative financial instruments	**125**	-	**$ 125**
	$ 45	$ -	**$ 45**
Derivative Financial Instruments Total:			
Change in unrealized mark to market loss/(gain) on derivative financial instruments	**$ 1,634**	$ (13,592)	**$ 15,226**
Realized loss on derivative financial instruments	**1,418**	1,391	**$ 27**
Total loss/(gain) on derivative financial instruments	**$ 3,052**	$ (12,201)	**$ 15,253**

During the three months ended June 30, 2010, cash provided by operating activities totalled $12.8 million or $0.14 per share as compared to cash provided by operating activities of $9.4 million, or $0.12 per trust unit during the same period in 2009. Cash provided by operating activities exceeded dividends by 2.2 times during the quarter ended June 30, 2010 as compared to 2.0 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 June 30, 2010, is primarily due to improved cash from working capital and increased interest, dividend and other income, partially offset by decreased cash flow from operating facilities, as compared to the same period in 2009.

Outlook

APCo

The APCo Renewable Energy division is expected to perform at or below long-term average resource conditions in the third quarter of 2010. In particular, the wind resource at the St. Leon facility returned to long term averages during the second quarter of 2010 and is expected to remain at or slightly below long term averages in the third quarter.

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 85,000 MW-hrs of energy to its customers on an annualized basis. APCo anticipates that the Tinker Assets, on an annualized basis, will provide greater than 50% 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 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.

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 475 tonnes of waste each day. The facility has completed a major capital upgrade totaling $9.8 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. APCo estimates the outage negatively affected operating profit by $2.0 million in the first half of 2010, but the completion of the capital upgrade is expected to positively impact the operating profit in the second half of 2010 by $0.2 million resulting in an overall negative impact on annual operating profit from EFW in 2010 of approximately $1.8 million as compared to the previous year.

APCo Thermal Energy division's Sanger facility is expected to operate at or above APCo's expectations for the third 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 its electricity and steam to the industrial host while maintaining an export to the grid between 10MW and 40MW of power. In addition the facility is participating in the capacity and forward reserve markets, where it anticipates it will earn revenue from providing "spinning reserve" to the grid and is dispatchable upon demand. The change to a forward capacity reserve market operating model is expected to negatively impact operating profit in the third quarter by approximately U.S. $0.8 million compared to the previous year.

For the full 2010 fiscal year, APCo currently anticipates operating profit at the Windsor Locks facility to be approximately U.S. $5.3 million compared to a historical operating profit of approximately U.S. $8.0 million. The profit expectations have increased from our first quarter expectations of U.S. $4.8 million primarily as a result of better than anticipated results in the second quarter of 2010 due to better than expected sales from dispatchable power. For a more detailed description of the options and expected impact see *Development Division - Windsor Locks*.

Liberty Water

On July 30, 2010, Liberty Water made an investment in its Hill Country facility, a part of the Silverleaf Resorts Inc. ("SRI") facilities in Comal County Texas. The investment of U.S. $2.25M was made under an agreement with SRI to increase the capacity of a wastewater treatment facility to support the growth of the utility. The investment is expected to earn the regulatory rate of return authorized for other Liberty Water utilities in the state of Texas.

Liberty Water is expecting modest growth in customers in 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.

Revenue increases from rate cases completed (pending regulatory approval) in Texas have contributed an additional $1.5M in run rate revenue for 2010. An exact determination of increased additional revenues from Arizona rate cases is not possible at this time as the timing of conclusion to the rate cases and final decision on rate increases are determined by the regulator. Liberty Water understands that there are an unusually high number of active rate cases proceeding through the Arizona Corporation Commission ("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 full annualized 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.

Liberty Electric

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. APUC formed a wholly owned subsidiary, Liberty Electric Co., to pursue investment 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. Based on the current regulatory procedural schedule, the closing of the transaction is expected to occur in the fourth quarter of 2010.

APCo: Renewable Energy

	Three months ended June 30			Six months ended June 30		
	Long Term Average Resource	**2010**	**2009**	**Long Term Average Resource**	**2010**	**2009**
Performance (MW-hrs sold)						
Quebec Region	**84,175**	**76,850**	89,075	**140,475**	**141,500**	154,575
Ontario Region	**40,100**	**22,800**	34,425	**78,050**	**52,725**	72,975
Manitoba Region	**86,000**	**85,900**	88,300	**191,000**	**165,075**	198,275
New England Region	**21,200**	**13,175**	23,625	**41,550**	**31,975**	45,675
New York Region	**27,800**	**20,025**	29,775	**55,150**	**43,950**	52,950
Western Region	**18,650**	**13,550**	14,775	**28,850**	**22,950**	25,125
Maritime Region	**59,300**	**42,100**	2,700	**87,300**	**73,500**	3,200
Total	**337,225**	**274,400**	282,675	**622,375**	**531,675**	552,775
Revenue						
Energy sales		**$ 19,974**	$ 17,462		**$ 42,192**	$ 36,425
Less:						
Cost of Sales – Energy*		**(745)**	-		**(2,960)**	-
Net Energy Sales		**$ 19,229**	$ 17,462		**$ 39,232**	$ 36,425
Other Revenue		**997**	-		**997**	-
Total Net Revenue		**$ 20,226**	**$ 17,462**		**$ 40,229**	**$ 36,425**
Expenses						
Operating expenses		**(5,304)**	(5,416)		**(11,214)**	(10,728)
Interest and Other income		**264**	308		**402**	552
Division operating profit (including other income)		**$ 15,186**	$ 12,354		**$ 29,417**	$ 26,249

* 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 Six Month Operating Results

For the six months ended June 30, 2010 the Renewable Energy division produced 531,675 MW-hrs of electricity, as compared to 552,775 MW-hrs, produced in the same period in 2009, a decrease of 3.8%. The level of production in 2010 represents sufficient renewable energy to supply the equivalent of 59,100 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 300,000 tons of CO_2 gas was prevented from entering the atmosphere in the first two quarters of 2010.

During the six months ended June 30, 2010, the division generated electricity equal to 85% of long-term projected average resources (wind and hydrology) as compared to 103% during the same period in 2009. In the first six months of 2010, several regions experienced resources at or below long-term averages. The Quebec region experienced resources equal to long-term averages, and the Maritime region and the Manitoba regions were approximately 15% below long-term averages. Four regions experienced results significantly below long-term averages including the Ontario region, which was 32% below long-term average resources, the New York and Western regions, which were 20% below long-term averages and the New England region which was 23% 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 quarter of 2010.

For the six months ended June 30, 2010, revenue from energy sales in the Renewable Energy division totalled $42.2 million, as compared to $36.4 million during the same period in 2009, an increase of $5.8 million. As the purchase of energy by the Energy Services Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the six months ended June 30, 2010, net revenue from energy sales in the Renewable Energy division totalled $39.2 million, as compared to $36.4 million during the same period in 2009, an increase of $2.8 million.

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 6.0% and decreased $1.0 million due to decreased average hydrology, as compared to the same period in 2009. Revenue from the Manitoba region increased $0.8 million due to an increase in weighted average energy rates of approximately 7.7%, offset by a decrease of $2.0 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 6.9%, 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 $2.6 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 $10.1 million in revenue, before energy purchases. This revenue consists of sales to local electric utilities and wholesale consumers in Northern Maine of $8.4 million, $0.9 million to a town in New Brunswick and $0.8 million representing merchant sales of production in excess of customer demand.

Other revenue for the six months ended June 30, 2010 totalled $1.0 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 six months ended June 30, 2010, energy purchase costs by the Energy Services Business totalled U.S. $2.9 million. During the first six months of 2010, the Energy Services Business purchased approximately 48,100 MW-hrs of energy at market and fixed rates averaging U.S. $59 per MW-hr. The Maritime region generated approximately 60% of the load required to service its customers as well as the Energy Services Business's customers in the six months ended June 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 six months ended June 30, 2010, operating expenses excluding energy purchases totalled $11.2 million, as compared to $10.7 million during the same period in 2009, an increase of $0.5 million. Operating expenses were impacted by $0.9 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 $1.5 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 $0.5 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 six months ended June 30, 2010. Operating expenses include costs incurred in the period of $0.8 million associated with the pursuit of various growth and development activities, including engineering and professional fees associated with the construction of the Red Lily I wind project as compared to development costs incurred of $0.9 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 $0.5 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the six months ended June 30, 2010, Renewable Energy's operating profit totalled $29.4 million, as compared to $26.2 million during the same period of 2009, representing an increase of $3.2 million or 12.1%. 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 quarter of 2010.

2010 Second Quarter Operating Results

For the quarter ended June 30, 2010, the Renewable Energy division produced 274,400 MW-hrs of electricity, as compared to 282,675 MW-hrs produced in the same period in 2009, a decrease of 2.9%. The level of production in 2010 represents sufficient renewable energy to supply the equivalent of 61,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 151,000 tons of CO_2 gas was prevented from entering the atmosphere in the second quarter of 2010.

During the quarter ended June 30, 2010, the division generated electricity equal to 81% of long-term projected average resources (wind and hydrology) as compared to 101% during the same period in 2009. In the second quarter of 2010, production in the Manitoba region was equal to long-term average resources while the Quebec region experienced resources 9% below long-term average resources. Several regions experienced results significantly below long-term averages including the Ontario region, which was 43% below long-term average resources, the New England region, which was 38% below long-term averages, and the New York, Western Canada and the Maritime regions, which were approximately 28% below long-term averages.

For the quarter ended June 30, 2010, revenue from energy sales in the Renewable Energy division totalled $20.0 million, as compared to $17.5 million during the same period in 2009, an increase of $2.5 million. As the purchase of energy by the Energy Services Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the quarter ended June 30, 2010, net revenue from energy sales in the Renewable Energy division totalled $19.2 million, as compared to $17.5 million during the same period in 2009, an increase of $1.8 million.

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 14.0%, offset by $0.8 million due to decreased average hydrology, as compared to the same period in 2009. Revenue from the Manitoba region increased $0.3 million due to an increase in weighted average energy rates of approximately 3.9%, offset by a decrease of $0.1 million due to a weaker 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 1.7%, 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 $1.7 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 $4.6 million in revenue, before energy purchases. This revenue consists of sales to local electric utilities and wholesale consumers in Northern Maine of $3.8 million, $0.4 million to a town in New Brunswick and $0.5 million representing merchant sales of production in excess of customer demand.

Other revenue for the three months ended June 30, 2010 totalled $1.0 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 $0.2 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the quarter ended June 30, 2010, energy purchase costs by the Energy Services Business totalled $0.7 million. During the quarter, the Energy Services Business purchased approximately 9,500 MW-hrs of energy at market and fixed rates averaging $75 per MW-hr. The Maritime region generated approximately 80% of the load required to service its customers as well as the Energy Services Business's customers in the three months ended June 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.

For the quarter ended June 30, 2010, operating expenses excluding energy purchases totalled $5.3 million, as compared to $5.4 million during the same period in 2009, a decrease of $0.1 million. Operating expenses were impacted by $0.3 million in decreased operating costs at the division's hydroelectric facilities, primarily due to lower variable operating costs tied to lower revenue and $0.2 million resulting from decreased repair and maintenance projects commenced in the quarter related to U.S. facilities. These increases were partially offset by $0.5 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 $1.0 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 engineering and professional fees associated with the construction of the Red Lily I wind project as compared to development costs incurred of $0.4 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 $0.2 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the quarter ended June 30, 2010, Renewable Energy's operating profit totalled $15.2 million, as compared to $12.4 million during the same period of 2009, representing an increase of $2.8 million or 22.9%. For the quarter ended June 30, 2010, Renewable Energy's operating profit did not meet APCo's expectations primarily due to lower hydrology in the second quarter of 2010 at the Canadian facilities.

Divisional Outlook – Renewable Energy

The APCo Renewable Energy division is expected to perform at or below long-term average resource conditions in the third quarter of 2010. In particular, the wind resource at the St. Leon facility returned to long-term averages during the second quarter of 2010 and is expected to remain at or slightly below long-term averages in the third quarter.

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 85,000 MW-hrs of energy to its customers on an annualized basis. 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 50% 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. In the second quarter of 2010, APCo completed the required assessments necessary to determine the work required to comply with the legislation.

APCo is required to submit plans for undertaking any remedial measures that are identified to comply with the legislation. As a result of the eleven completed assessments and a preliminary evaluation of the associated remedial work, APCo has estimated capital expenditures of approximately $17.5 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	17,500	200	6,200	5,800	2,800	2,500

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Mont-Laurier facilities. During the first quarter, APCo revised its assumptions related to the anticipated timing of the Donnacona capital expenditures and currently anticipates the majority of the costs associated with the facility will be incurred in fiscal 2011 and 2012. 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 June 30		**Six months ended June 30**	
	2010	**2009**	**2010**	**2009**
Performance (MW-hrs sold)	**99,850**	137,987	**239,050**	280,373
Performance (tonnes of waste processed)	-	35,716	**6,550**	76,999
Revenue				
Energy sales	**$ 11,771**	$ 14,911	**$ 26,070**	$ 33,449
Less:				
Cost of Sales – Fuel *	**(5,294)**	(5,922)	**(11,539)**	(15,773)
Net Energy Sales Revenue	**$ 6,477**	$ 8,989	$ **14,531**	$ 17,676
Waste disposal sales	**90**	3,178	**1,007**	6,861
Other revenue	**341**	1,066	**544**	2,374
Total net revenue	**$ 6,908**	$ 13,233	**$ 16,082**	$ 26,911
Expenses				
Operating expenses *	**(5,489)**	(7,785)	**(11,750)**	(16,077)
Interest and other income	**131**	124	**270**	256
Division operating profit (including interest and dividend income)	**$ 1,550**	$ 5,572	**$ 4,602**	$ 11,090

* 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 a 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 Six Month Operating Results

In the first two quarters of 2010, the EFW facility processed 6,550 tonnes of municipal solid waste as compared to 76,999 tonnes processed in the same period of 2009, a decrease of 91.5%. 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 3,000 tonnes of waste from landfill sites in the first six months of 2010.

During the six months ended June 30, 2010, the business unit produced 239,050 MW-hrs of energy as compared to 280,373 MW-hrs of energy in the comparable period of 2009. During the six months ended June 30, 2010, the business unit's performance decreased by 27,500 MW-hrs at the Windsor Locks facility, 10,400 MW-hrs at the land-fill gas ("LFG") facilities and 4,250 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 where revenues are earned from capacity payments from ISO NE and forward reserve market payments from the thirty minute operating reserve ("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 six months ended June 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 1,700 MW-hrs at the Valley Power facility.

For the six months ended June 30, 2010, revenue in the Thermal Energy division totalled $27.6 million, as compared to $42.7 million during the same period in 2009, a decrease of $15.1 million. 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 six months ended June 30, 2010, net energy sales revenue at the Thermal Energy division totalled $14.5 million, as compared to $17.7

million during the same period in 2009, a decrease of $3.2 million. The decrease in revenue from energy sales was primarily due to a decrease of $0.4 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 $2.5 million as a result of the change in operating model of the facility, partially offset by $0.5 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 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 $4.2 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 six months ended June 30, 2010 totalled $1.0 million, as compared to $6.9 million during the same period in 2009. The EFW facility did not operate in the second quarter as a result of the unplanned outage in January 2010.

Other revenue for the six months ended June 30, 2010 totalled $0.5 million, as compared to $2.4 million during the same period in 2009. The decrease in other revenue was primarily due to a decrease of $0.9 million at the hydro-mulch facility due to reduced customer demand in the first two quarters of 2010. In the comparable period in 2009, other revenue included $0.6 million from APCo's MGT facility which was not operational in the current period.

For the six months ended June 30, 2010, fuel costs at Sanger and Windsor Locks totalled U.S. $11.1 million, as compared to U.S. $13.0 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 $0.2 million (4%), primarily the result of a 16% decrease in the average landed cost of natural gas per mmbtu combined with a 7% 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. $4.71 per mmbtu. This was partially offset by an increase in the overall natural gas expense at Sanger of $0.2 million (28%), primarily the result of a 27% increase in the average landed cost of natural gas per mmbtu combined with a 36% reduction in volume of natural gas consumed as compared to the same period in 2009. The average landed cost of natural gas at the Sanger facility was U.S. $5.23 per mmbtu. The division reported decreased fuel costs of $2.4 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the six months ended June 30, 2010, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $11.7 million, as compared to $16.1 million during the same period in 2009, a decrease of $4.3 million. The decrease in operating expenses for the quarter was primarily due to reduced operating costs of $4.1 million at the EFW facility resulting from the outage at the facility, reduced material costs of $0.5 million at the hydro-mulch facility resulting from lower production, and $0.5 million of lower costs due to the closing of the LFG facilities partially offset by increased natural gas expense of $1.4 million at BCI 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 $1.0 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

Interest and other income for the six months ended June 30, 2010 totalled $0.3 million, consistent with the same period in 2009. During the 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 six months ended June 30, 2010, the Thermal Energy division's operating profit totalled $4.6 million, as compared to $11.1 million during the same period in 2009, representing a decrease of $6.5 million or 59%. Operating profit in the Thermal Energy division did not meet overall expectations for the six months ended June 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 Second Quarter Operating Results

In the second quarter of 2010, the EFW facility did not process any municipal solid waste as compared to 35,716 tonnes processed in the same period of 2009. See the discussion of the year to date operating results and *Divisional Outlook – Thermal Energy,* below for further detail on the status of this facility.

During the quarter ended June 30, 2010, the business unit produced 99,850 MW-hrs of energy as compared to 137,987 MW-hrs of energy in the comparable period of 2009. During the quarter ended June 30, 2010, the business unit's performance decreased by 26,700 MW-hrs at the Windsor Locks facility, 8,200 MW-hrs at the LFG facilities and 2,200 MW-hrs from EFW's steam turbine 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 decrease in electrical generation at the EFW facility was the result of the unplanned outage which occurred in January 2010. During the quarter ended June 30, 2010, the LFG facilities did not operate as APCo had initiated a process to close these facilities in the prior quarter.

For the quarter ended June 30, 2010, revenue in the Thermal Energy division totalled $12.2 million, as compared to $19.2 million during the same period in 2009, a decrease of $7.0 million. 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 June 30, 2010, net energy sales revenue at the Thermal Energy division totalled $6.5 million, as compared to $9.0 million during the same period in 2009, a decrease of $2.5 million. The decrease in revenue from energy sales was primarily due to a decrease of $2.1 million at the Windsor Locks facility as a result of decreased production volumes for the reasons discussed in the year to date operating results, partially offset by $0.8

million at Windsor Locks due to increased energy rates, as a result of a combination of higher average landed price per mmbtu for natural gas and the impact of capacity revenues earned from ISO NE. Lower revenues were also partially offset by $0.4 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 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 $1.5 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 June 30, 2010 totalled $0.1 million, as compared to $3.2 million during the same period in 2009. The decrease in throughput at the EFW facility was the result of the unplanned outage that occurred in January 2010.

Other revenue for the quarter ended June 30, 2010 totalled $0.3 million, as compared to $1.1 million during the same period in 2009. The decrease in other revenue was primarily due to a decrease of $0.5 million at the hydro-mulch facility due to reduced customer demand in the quarter.

For the quarter ended June 30, 2010, fuel costs at Sanger and Windsor Locks totalled U.S $5.1 million, consistent with 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 14% reduction in volume of natural gas consumed partially offset by a 13% 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. $5.16 per mmbtu. This was partially offset by an increase in the natural gas expense at Sanger of $0.2 million (28%), primarily the result of a 32% 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. $4.56 per mmbtu. The division reported decreased fuel costs of $0.7 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the quarter ended June 30, 2010, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $5.5 million, as compared to $7.8 million during the same period in 2009, a decrease of $2.3 million. The decrease in operating expenses for the quarter was primarily due to reduced operating costs of $2.5 million at the EFW facility resulting from the outage at the facility, reduced material costs of $0.3 million at the hydro-mulch facility resulting from lower production, and $0.2 million of reduced operating costs at the LFG facilities partially offset by increased natural gas expense of $0.9 million at BCI 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 $0.2 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 $0.4 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 June 30, 2010 totalled $0.1 million, consistent with the same period in 2009. During the 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 June 30, 2010, the Thermal Energy division's operating profit totalled $1.6 million, as compared to $5.6 million during the same period in 2009, representing a decrease of $4.0 million or 72%. Operating profit in the Thermal Energy division did not meet overall expectations for the quarter ended June 30, 2010, primarily due to the unplanned outage at the EFW facility and lower earnings at the Windsor Locks facility resulting from the changed operating model at the facility.

Divisional Outlook – Thermal Energy

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 475 tonnes of waste each day. The facility has completed a major capital upgrade totaling $9.8 million which included new boiler tubes on all units. 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. APCo estimates the outage negatively affected operating profit by $2.0 million in the first half of 2010, but the completion of the capital upgrade is expected to positively impact the operating profit in the second half of 2010 by $0.2 million resulting in an overall negative impact on annual operating profit from EFW in 2010 of approximately $1.8 million as compared to the previous year.

APCo Thermal Energy division's Sanger facility is expected to operate at or above APCo's expectations for the third 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 this is offset by higher revenues expected 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 its electricity and steam to the industrial host while maintaining an export to the grid between 10MW and 40MW of power. In addition the facility is participating in the TMOR and forward reserve market, where it anticipates it will earn revenue from providing "spinning reserve" to the grid and is dispatchable upon demand. The change to a forward capacity reserve market operating model is expected to negatively impact operating profit in the third quarter by approximately U.S. $0.8 million compared to the previous year.

For the full 2010 fiscal year, APCo currently anticipates operating profit at the Windsor Locks facility to be approximately U.S. $5.3 million compared to a historical operating profit of approximately U.S. $8.0 million. This operating profit estimate assumes participation in the summer 2010 and the winter 2010/2011 forward reserve auctions. TMOR has cleared at US $14 per MW month for the last 7 forward capacity reserve procurement periods (two periods annually). The profit expectations have increased from first quarter expectations primarily as a result of better than anticipated results in the second quarter of 2010 due to better than expected sales from dispatchable power. 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 to include a larger proportion of renewable power. These factors have created a favourable policy environment for independent producers and developers of renewable and power generation, particularly in the areas of wind, hydro 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 will 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 of 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. 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 the RFP to follow.

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. Over the past year APCo has successfully worked 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.

Discussions with the OPA indicate that energy procurement initiatives will be positively influenced by the GEA which received Royal Assent in May 2009. 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 summer or early fall 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. 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.

Since the announcement, the construction phase of Red Lily I has commenced. 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%. With the commencement of construction of Red Lily I, APCo earned construction supervision fees of approximately $0.8 million in the second quarter and will earn a total of approximately $2.2 million during fiscal 2010.

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.

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.

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. The facility had two key energy agreements. The first agreement was the PPA with CL&P which expired in April 2010. The expiration of the CL&P PPA impacts operations beyond April 2010. The second agreement is the Energy Services Agreement ("ESA") with Ahlstrom Windsor Locks, LLC ("Ahlstrom"), a leading paper and non woven materials manufacturer, which, if not further extended by mutual agreement, will continue until 2017.

Subsequent to the expiration of the CL&P PPA, APCo bid its available capacity of approximately 40 MW which previously served the CL&P requirements into the TMOR 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.

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 US $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. 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.

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 and TMOR 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.

Thermal Energy

The EFW facility is designed to incinerate approximately 475 tonnes per day of municipal solid waste, producing steam which can be used in the production of electricity or to supply the internal steam load for a nearby manufacturing company. There is potential to expand the EFW facility's throughput capacity by between 40,000 and 100,000 tonnes annually. APCo is currently evaluating the feasibility of an expanded facility. APCo is also engaged in discussions with the Region of Peel to establish a new long term contract for a reliable supply of municipal solid waste.

LIBERTY WATER

	Six months ended June 30		Six months ended June 30	
	2010	**2009**	**2010**	**2009**
Number of				
Wastewater connections			**35,060**	34,399
Wastewater treated (millions of gallons)			**1,000**	975
Water distribution connections			**37,357**	36,693
Water sold (millions of gallons)			**2,300**	2,600
	US $	**US $**	**Can $**	**Can $**
Assets for regulatory purposes (U.S. $)	**152,069**	**149,530**		
Revenue				
Wastewater treatment	**$ 9,555**	$ 8,840	**$ 9,944**	$ 10,560
Water distribution	**7,226**	7,230	**7,520**	8,638
Other Revenue	**278**	340	**289**	406
	$ 17,059	$ 16,410	**$ 17,753**	$ 19,604
Expenses				
Operating expenses	**(10,463)**	(9,916)	**(10,908)**	(11,977)
Other income (expense)	**10**	(34)	**11**	(37)
Business Unit operating profit (including other income)	**$ 6,606**	$ 6,460	**$ 6,856**	$ 7,590

Liberty Water is committed to being the 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 35,060 wastewater connections as at June 30, 2010, as compared to 34,399 as at June 30, 2009, an increase of 661 in the period or 1.9%. Liberty Water had 37,357 water distribution connections as at June 30, 2010, as compared to 36,693 as at June 30, 2010, representing an increase of 664 in the period or 1.8%. Total connections include approximately 2,037 vacant wastewater connections and 1,268 vacant water distributions connections. Liberty Water's marginal change in water distribution and wastewater treatment customer base during the period is due to the acquisition of a small utility in Texas during the first quarter of 2010 and limited organic growth at Liberty Water's other facilities.

Liberty Water has investments in regulatory assets of U.S. $152.1 million across four states as at June 30, 2010, as compared to U.S. $149.5 million as at June 30, 2009 and has active proceedings in Texas and Arizona to allow it to earn its full regulatory return on its investment in regulatory assets.

2010 Six Month Operating Results

During the six months ended June 30, 2010, Liberty Water provided approximately 1.0 billion U.S. gallons of water to its customers, treated approximately 2.3 billion U.S. gallons of wastewater and sold approximately 145 million U.S. gallons of treated effluent.

For the six months ended June 30, 2010, Liberty Water's revenue totalled U.S. $17.1 million as compared to U.S. $16.4 million during the same period in 2009, an increase of U.S. $0.6 million.

Revenue from water distribution totalled U.S. $7.2 million, consistent with the same period in 2009. The six month water distribution revenue was impacted by an increase of U.S. $0.3 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 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 Litchfield Park facility ("LPSCo") and U.S. $0.1 million lower customer demand at six water distribution facilities, as compared to the same period in 2009.

Revenue from wastewater treatment totalled U.S. $9.6 million, as compared to U.S. $8.8 million during the same period in 2009, an increase of U.S. $0.7 million. The six month wastewater treatment revenue was impacted by increased revenue of U.S. $0.6 million at the four Texas Silverleaf facilities, the Woodmark facility and the Tall Timbers facility, primarily due to the ongoing rate cases and the related implementation of interim rate increases, U.S. $0.2 million at LPSCo primarily due to higher treated effluent revenue, 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 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 six months ended June 30, 2010, operating expenses totalled U.S. $10.5 million, as compared to U.S. $9.9 million during the same period in 2009. Overall expenses increased U.S. $0.5 million or 5.5% as compared to the same period in 2009. Operating expenses increased U.S. $0.8 million as a result of increased wages, salary and other operating costs, partially offset by decreases of U.S. $0.2 million in reduced contracted services expenses and U.S. $0.2 million in reduced utilities and consumables expenses as compared to the same period in 2009. The comparable period includes expenses of U.S. $0.4 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.

For the six months ended June 30, 2010, Liberty Water's operating profit totalled U.S. $6.6 million as compared to U.S. $6.5 million in the same period in 2009, an increase of U.S. $0.1 million or 2.2%. Liberty Water's operating profit met expectations for the six months ended June 30, 2010.

Measured in Canadian dollars, for the six months ended June 30, 2010, Liberty Water's revenue totalled $17.8 million as compared to $19.6 million during the same period in 2009, a decrease of $1.9 million. Revenue from wastewater treatment totalled $9.9 million, as compared to $10.6 million during the same period in 2009, a decrease of $0.6 million. Revenue from water distribution totalled $7.5 million, as compared to $8.6 million during the same period in 2009, a decrease of $1.1 million. Liberty Water reported decreased revenue from operations of $2.5 million in the first six 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 six months ended June 30, 2010, operating expenses totalled $10.9 million, as compared to $12.0 million during the same period in 2009. Liberty Water reported lower expenses from operations of $1.1 million as a result of the stronger Canadian dollar, as compared to the same period in 2009.

For the six months ended June 30, 2010, Liberty Water's operating profit totalled $6.9 million as compared to $7.6 million in the same period in 2009, a decrease of $0.7 million or 9.7%. Liberty Water's operating profit met expectations for the six months ended June 30, 2010.

	Three months ended June 30		**Three months ended June 30**	
	2010	**2009**	**2010**	**2009**
Number of				
Wastewater connections			**35,060**	34,179
Wastewater treated (millions of gallons)			**500**	475
Water distribution connections			**37,357**	36,527
Water sold (millions of gallons)			**1,400**	1,550
	US $	**US $**	**Can $**	**Can $**
Assets for regulatory purposes (U.S. $)	**152,069**	**149,530**		
Revenue				
Wastewater treatment	**$ 4,914**	$ 4,399	**$ 5,085**	$ 5,053
Water distribution	**4,152**	4,075	**4,297**	4,681
Other Revenue	**122**	171	**121**	198
	$ 9,188	$ 8,645	**$ 9,503**	$ 9,932
Expenses				
Operating expenses	**(5,279)**	(5,064)	**(5,480)**	(5,891)
Other income (expense)	**-**	(34)	**-**	(38)
Business Unit operating profit (including other income)	**$ 3,909**	$ 3,547	**$ 4,023**	$ 4,003

2010 Second Quarter Operating Results

During the quarter ended June 30, 2010, Liberty Water provided approximately 1.4 billion U.S. gallons of water to its customers, treated approximately 500 million U.S. gallons of wastewater and sold approximately 115 million U.S. gallons of treated effluent.

For the quarter ended June 30, 2010, Liberty Water's revenue totalled U.S. $9.2 million as compared to U.S. $8.6 million during the same period in 2009, an increase of U.S. $0.5 million.

Revenue from water distribution totalled U.S. $4.2 million, as compared to U.S. $4.1 million during the same period in 2009, an increase of U.S. $0.1 million. The second 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, partially offset by decreased revenue of U.S. $0.1 million primarily due to lower commercial water sales at LPSCo and lower customer demand at six water distribution facilities, as compared to the same period in 2009.

Revenue from wastewater treatment totalled U.S. $4.9 million, as compared to U.S. $4.4 million during the same period in 2009, an increase of U.S. $0.5 million. The second quarter wastewater treatment revenue was impacted by increased revenue of U.S. $0.3 million at the four Texas Silverleaf facilities, the Woodmark facility and the Tall Timbers facility, primarily due to the ongoing rate cases and the related implementation of interim rate increases, U.S. $0.1 million at LPSCo primarily due to higher treated effluent revenue 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.

For the quarter ended June 30, 2010, operating expenses totalled U.S. $5.3 million, as compared to U.S. $5.1 million during the same period in 2009. Overall expenses increased U.S. $0.2 million or 4.2% as compared to the same period in 2009. Operating expenses increased U.S. $0.3 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 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.

For the quarter ended June 30, 2010, Liberty Water's operating profit totalled U.S. $3.9 million as compared to U.S. $3.5 million in the same period in 2009, an increase of U.S. $0.4 million or 10.2%. Liberty Water's operating profit met expectations for the three months ended June 30, 2010.

Measured in Canadian dollars, for the quarter ended June 30, 2010, Liberty Water's revenue totalled $9.5 million as compared to $9.9 million during the same period in 2009, a decrease of $0.4 million. Revenue from wastewater treatment totalled $5.1 million, consistent with the same period in 2009. Revenue from water distribution totalled $4.3 million, as compared to $4.7 million during the same period in 2009, a decrease of $0.4 million. Liberty Water reported decreased revenue from operations of $1.0 million in the second 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 June 30, 2010, operating expenses totalled $5.5 million, as compared to $5.9 million during the same period in 2009. Liberty Water reported lower expenses from operations of $0.6 million as a result of the stronger Canadian dollar, as compared to the same period in 2009.

For the quarter ended June 30, 2010, Liberty Water's operating profit totalled $4.0 million, consistent with the same period in 2009. Liberty Water's operating profit met expectations for the three months ended June 30, 2010.

Outlook – Liberty Water

On July 30, 2010, Liberty Water made an investment in its Hill Country facility, a part of the SRI facilities in Comal County Texas. The investment of U.S. $2.25M was made under an agreement with SRI to increase the capacity of a wastewater treatment facility to support the growth of the utility. The investment is expected to earn the regulatory rate of return authorized for other Liberty Water utilities in the state of Texas.

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 (pending regulatory approval) in Texas have contributed an additional $1.5M in run rate revenue for 2010. An exact determination of increased additional revenues from Arizona rate cases is not possible at this time as the timing of conclusion to the rate cases and final decision on rate increases are determined by the regulator. 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 full annualized 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	Estimated Annual U.S. $ Revenue Increase as Filed
Facility	
Arizona	
Black Mountain*	$ 0.7 million
Texas	
Texas Utilities (Silverleaf – 4 utilities)**	$ 1.2 million
Tall Timbers **	$ 0.2 million
Woodmark**	$ 0.1 million

* Recommended Order & Opinion received on August 3, 2010. New rates anticipated to be implemented on September 1, 2010.

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

Rate Cases Awaiting Recommended Order & Opinion	Estimated Annual U.S. $ Revenue Increase as Filed
Facility	
Arizona	
LPSCo	$ 12.5 million
Rio Rico	$ 2.0 million

Rate Cases With Pending Hearing	
Facility	
Arizona	
Bella Vista, Northern and Southern Sunrise	$ 1.5 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. It is anticipated that the regulatory review of the proposed rates and tariffs for the Arizona facilities would be completed in 2010.

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 for 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 completion of these three rate cases is pending final approval from the TCEQ Executive Director.

APUC: Corporate

	Three months ended June 30		Six months ended June 30	
	2010	2009	**2010**	2009
Corporate and other expenses:				
Administrative expenses	**2,990**	2,544	**5,905**	4,931
Management costs	**-**	212	**-**	425
Loss / (Gain) on foreign exchange	**404**	(1,892)	**366**	(1,315)
Interest expense	**6,166**	5,143	**12,413**	10,657
Interest, dividend and other Income	**(942)**	(778)	**(1,677)**	(1,514)
Loss (gain) on derivative financial instruments	**3,052**	(12,201)	**2,140**	(8,703)
Income tax expense (recovery)	**(412)**	651	**(2,618)**	(4,341)

2010 Six Month Corporate and Other Expenses

During the six months ended June 30, 2010, management and administrative expenses totalled $5.9 million, as compared to $5.4 million in the same period in 2009. The expense increase in the six months ended June 30, 2010 results from increased capital taxes resulting from APUC's effective conversion to a corporation in 2009 and developing the IFRS conversion plan as well as added requirements to administer 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 six months ended June 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 though the consolidated statement of operations. For the six months ended June 30, 2010, APUC reported a foreign exchange loss of $0.4 as compared to a gain of $1.3 million during the same period in 2009. The six months ended June 30, 2010 experienced an increase in value of the U.S. dollar of 1.3% which resulted in unrealized losses 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 5.0% 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 six months ended June 30, 2010, interest expense totalled $12.4 million as compared to $10.7 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 six months ended June 30, 2010, interest, dividend and other income totalled $1.7 million as compared to $1.5 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 $2.6 million was recorded in the six months ended June 30, 2010, as compared to a recovery of $4.3 million during the same period in 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 quarter ended June 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 June 30, 2009 is based on a publicly traded income trust structure. The income tax recovery in the six months ended June 30, 2010 primarily relates to the effective conversion to a corporation from an income trust and increased operating losses as compared to the same period in 2009.

2010 Second Quarter Corporate and Other Expenses

During the quarter ended June 30, 2010, management and administrative expenses totalled $3.0 million, as compared to $2.8 million in the same period in 2009. The expense increase in the three months ended June 30, 2010 results from increased capital taxes resulting from APUC's effective conversion to a corporation in 2009 and developing the IFRS conversion plan as well as added requirements to administer 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. For the three months ended June 30, 2010, APUC reported a foreign exchange loss of $0.4 million as compared to a gain of $1.9 million during the same period in 2009. The three months ended June 30, 2010 experienced an increase in value of the U.S. dollar of 4.8% which resulted in unrealized losses 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 7.8% 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 June 30, 2010, interest expense totalled $6.2 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, 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 quarter ended June 30, 2010, interest, dividend and other income totalled $0.9 million as compared to $0.8 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 $0.4 million was recorded in the three months ended June 30, 2010, as compared to an expense of $0.7 million during the same period in 2009. On October 27, 2009, Algonquin effectively converted from a publicly traded income trust to a publicly traded corporation. The income tax recovery in the three months ended June 30, 2010 primarily relates to increased operating losses as compared to the same period in 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 June 30		Six months ended June 30	
	2010	**2009**	**2010**	**2009**
Net earnings (loss)	**$ (2,236)**	$ 15,302	**$ 1,215**	$ 19,545
Add:				
Income tax provision (recovery)	**(412)**	651	**(2,618)**	(4,341)
Interest expense	**6,166**	5,143	**12,413**	10,657
(Gain) / loss on derivative financial instruments	**3,052**	(12,201)	**2,140**	(8,703)
(Gain) / loss on foreign exchange	**404**	(1,892)	**366**	(1,315)
Amortization	**11,591**	11,353	**22,920**	23,020
Other	**146**	1,596	**211**	2,204
Adjusted EBITDA	**$ 18,711**	$ 19,952	**$ 36,647**	$ 41,067

For the six months ended June 30, 2010, Adjusted EBITDA totalled $36.6 million as compared to $41.1 million, a net decrease of $4.4 million or 10.8% as compared to the same period in 2009. Adjusted EBITDA was impacted by declines at various facilities and regions of approximately $12.5 million in the six months ended June 30, 2010. On a percentage basis, the major factors for the decline include lower earnings from operations in the Renewable Energy division (14%) primarily due to lower hydrology, at the St. Leon facility (17%) primarily due to a lower wind resource, at the EFW facility (16%) due to the major capital improvements, at the BCI facility (16%) and due to the stronger Canadian dollar (17%) as compared to the previous year. These declines were partially offset by increases in Adjusted EBITDA of approximately $8.1 million in the six months ended June 30, 2010. On a percentage basis, the major factors for the increases are the inclusion of operating income from the Tinker Assets (70%) and the revenue related to construction fees, interest and expense reimbursements resulting from the Red Lily I project (22%), as compared to the same period in 2009.

For the quarter ended June 30, 2010, Adjusted EBITDA totalled $18.7 million as compared to $20.0 million, a decrease of $1.2 million or 6.2% as compared to the same period in 2009. Adjusted EBITDA was impacted by declines at various facilities and regions of approximately $6.4 million in the three months ended June 30, 2010. On a percentage basis, the major factors for the decline include lower earnings from operations in the Renewable Energy division (26%) primarily due to lower hydrology, at the Windsor Locks facility (19%) primarily due to the expiry of the PPA and change in operating model, at the BCI facility (17%), at the EFW facility (9%) due to the major capital improvements, at the St. Leon facility (6%) primarily due to a lower wind resource and due to the stronger Canadian dollar (15%) as compared to the previous year. These declines were partially offset by increases in Adjusted EBITDA of approximately $5.2 million in the three months ended June 30, 2010. On a percentage basis, the major factors for the increases are the inclusion of operating income from the Tinker Assets (57%) and the revenue related to construction fees, interest and expense reimbursements resulting from the Red Lily I project (34%), as compared to the same period in 2009.

Reconciliation of adjusted net earnings/(loss) to net earnings/(loss)

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/(loss) 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 June 30		**Six months ended June 30**	
	2010	**2009**	**2010**	**2009**
Net earnings (loss)	**$ (2,236)**	$ 15,302	**$ 1,215**	$ 19,545
Add:				
Loss (gain) on derivative financial instruments, net of tax	**1,687**	(9,561)	**1,270**	(6,472)
Loss (gain) on foreign exchange, net of tax	**404**	(1,892)	**366**	(1,315)
Adjusted net earnings (loss)	**$ (145)**	$ 3,849	**$ 2,851**	$ 11,758
Adjusted net earnings per unit*	**$ (0.00)**	$ 0.05	**$ 0.03**	$ 0.15

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

For the six months ended June 30, 2010, adjusted net earnings totalled $2.9 million as compared to $11.8 million, a decrease of $8.9 million as compared to the same period in 2009. The decrease in adjusted net earnings in the six months ended June 30, 2010 is primarily due to lower earnings from operations as compared to the same period in 2009.

For the three months ended June 30, 2010, adjusted net loss totalled $0.1 million as compared to adjusted net earnings of $3.8 million, a decrease of $4.0 million as compared to the same period in 2009. The decrease in adjusted net loss in the three months ended June 30, 2010 is primarily due to lower earnings from operations as compared to the same period in 2009.

Summary of Property, Plant and Equipment Expenditures

	Three months ended June 30		Six months ended June 30	
	2010	**2009**	**2010**	**2009**
APCo				
Renewable Energy Division				
Capital expenditures	**$ 679**	$ 207	**$ 943**	$ 505
Acquisition of operating entities	-	-	**40,363**	-
Total	**$ 679**	$ 207	**$ 41,306**	$ 505
Thermal Energy Division				
Capital expenditures	**$ 6,097**	$ 920	**$ 9,932**	$ 1,974
Total	**$ 6,097**	$ 920	**$ 9,932**	$ 1,974
LIBERTY WATER				
Capital Investment in regulatory assets	**$ 991**	$ 16	**$ 1,036**	$ 4,318
Acquisition of operating entities	-	50	**2,039**	50
	$ 991	$ 66	**$ 3,075**	$ 4,368
Consolidated (includes Corporate)				
Capital expenditures	**$ 6,838**	$ 1,226	**$ 10,952**	$ 2,578
Capital investment in regulatory assets	**991**	16	**1,036**	4,318
Acquisition of operating entities	-	50	**42,402**	50
Total	**$ 7,829**	$ 1,292	**$ 54,390**	$ 6,946

APUC's consolidated capital expenditures in the six months ended June 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 $4.5 million and $8.0 million, including approximately $5.0 million related to ongoing requirements by Liberty Water, $1.0 million related to the APCo Thermal division, and $2.5 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 Six Month Property Plant and Equipment Expenditures

During the six months ended June 30, 2010, APCo incurred capital expenditures of $11.0 million, as compared to $2.6 million during the comparable period in 2009. APCo also invested $40.4 million to acquire operating assets/entities during the six months ended June 30, 2010, as compared to nil during the comparable period in 2009.

During the six months ended June 30, 2010, APCo Renewable Energy division's capital expenditures were not significant, consistent with the comparable period in 2009. The APCo Renewable Energy division's acquisition of operating assets primarily relate to the Tinker Assets located in New Brunswick and Maine.

During the six months ended June 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 six months ended June 30, 2010, Liberty Water did not invest significant capital into regulatory assets, as compared to an investment of $4.3 million in the comparable period. During the six months ended June 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 Second Quarter Property Plant and Equipment Expenditures

During the three months ended June 30, 2010, APCo incurred capital expenditures of $6.8 million, as compared to $1.2 million during the comparable period in 2009.

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

During the three months ended June 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 June 30, 2010, Liberty Water did not invest significant capital into regulatory assets, as compared to nil 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 Q2	2010 Q1	2009 Q4	2009 Q3	2009 Q2
Committed and available Facilities	$162,800	$ 177,950	$179,500	$ 176,700	$ 189,050
Funds Drawn on Facilities	(102,800)	(91,650)	(94,000)	(129,000)	(134,000)
Letters of Credit issued	(34,600)	(32,400)	(33,100)	(33,400)	(35,250)
Remaining available Facilities	**$ 25,400**	**$ 53,900**	**$ 52,400**	**$ 14,300**	**$ 19,800**
Cash on Hand	2,400	750	2,800	7,700	6,900
Total liquidity and capital reserves	**$ 27,800**	**$ 54,650**	**$ 55,200**	**$ 22,000**	**$ 26,700**

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

As at June 30, 2010, Can. $81.5 million and U.S. $20.0 million had been drawn on the Facilities as compared to $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 June 30, 2010. In addition to amounts actually drawn, there was $34.6 million in letters of credit currently outstanding as at June 30, 2010. As at June 30, 2010, APUC and its subsidiaries had $25.4 million of committed and available bank facilities remaining and $2.4 million of cash resulting in $27.8 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.

CONTRACTUAL OBLIGATIONS

Information concerning contractual obligations as of June 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]	$ 252,428	$ 106,274	$ 71,457	$ 3,683	$ 71,014
Convertible Debentures	$186,669	-	-	63,452	123,217
Interest on long term debt obligations	$ 142,785	20,636	37,061	33,321	51,767
Purchase obligations	$ 29,723	29,723	-	-	-
Derivative financial instruments:					
Currency forward	$ 1,612	512	1,100	-	-
Interest rate swap	$ 7,426	3,903	2,484	962	77
Energy forward contracts	$ 1,484	1,484	-	-	-
Capital lease obligations	$ 663	204	373	86	-
Other obligations	$ 10,237	516	1,032	1,032	7,657
Total obligations	$ 633,027	$ 163,252	$ 113,507	$ 102,536	$ 253,732

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 six months ended June 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 ("TSE") while Algonquin's trust units concurrently ceased trading on the TSE.

As at June 30, 2010, APUC had 95,099,989 issued and outstanding shares on a fully diluted basis.

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 APMI. 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 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 six months ended June 30, 2010, APUC received $0.2 million (2009 - $nil) 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 $2.3 million. The payments on these assets are current and the debt matures in 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.

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. A principal amount of $692 Series 1A Debentures was converted at the option of holders into 169,480 shares of APUC during the three months ended June 30, 2010 and a principal amount of $3,491 Series 1A Debentures was converted 855,689 shares of APUC during the six months ended June 30, 2010.

On June 30, 2010, there were 63,451 Series 1A Debentures outstanding with a face value of $63,451.

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 June 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 maturing on June 30, 2017 ("Series 3 Debentures") in a principal amount of $63,250. On June 30, 2010, there were 63,250 Series 3 Debentures outstanding with a face value of $63,250.

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 TSE 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 (20%) 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 (50%) 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 (50%) 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 voted in favour of establishing a stock option plan (the "Plan") to encourage ownership of the APUC's common shares by its 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 extent to which each option vests and is exercisable from time to time during the term of the option and other terms and conditions relating to each option shall be determined by the Board from time to time. As of June 30, 2010, the Company has not granted any options under the Plan.

RELATED PARTY TRANSACTIONS

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

- Up to December 21, 2009, APMI provided management services to the Algonquin, a subsidiary of APUC, 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 the Algonquin which were provided by APMI. Therefore, for the three and six months ended June 30, 2010, APMI was not paid a management fee. For the three and six months ended June 30, 2009, APMI was paid on a cost recovery basis for all costs incurred and charged APUC $212 and $425 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 six months ended June 30, 2010 were $81 (2009 - $86) and $163 (2009 - $168) respectively.
- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. During the three and six months ended June 30, 2010, APUC incurred costs in connection with the use of the aircraft of $60 (2009 - $60) and $208 (2009 - $140) respectively and amortization expense related to the advance against expense reimbursements of $6 (2009 - $17) and $63 (2009 - $73) respectively.
- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by 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 $87 (2009 - $103) and $126 (2009 - $157) for the three and six months ended June 30, 2010 respectively.
- APMI is entitled to 50% of the cash flow above 15% return on investment for the BCI project pursuant to its project management contract. During the six months ended June 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 June 30, 2010 this amount is accrued and included in accounts payable on the consolidated balance sheet.
- A member of the Board 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 approximately 24,100 MW-hrs of energy on ISO NE on behalf of the Energy Services Business and was paid 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. No expenses were incurred in the three and six months ended June 30, 2010 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.

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

TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. 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 (\$0.035 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 quarter ended June 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 six months ended June 30, 2010 APUC realized cash gains of \$0.3 million and \$0.4 million respectively on managing its forward contracts.

The following chart sets out as at June 30, 2010 the amounts, hedge proceeds and average hedged rates over the term of the foreign exchange forward contracts outstanding.

	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)	**$ (1,612)**	n/a	**(1,011)**	**(589)**	**(12)**
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 June 30, 2010, the exercise of these forward contracts will result in the use of cash of $1.0 million in fiscal 2011 and result in the use of cash of $0.6 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 June 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 25,000 MW-hrs of net energy over the next 8 months at an average rate of approximately $75 per MW-hr. The mark to market value of these forward energy hedge contracts at June 30, 2010 was a net million liability of U.S. $1.5 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 Can. $81.5 million and U.S. $20.0 million as at June 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 Can $0.8 million and U.S. $0.2 million annually. Algonquin has fixed for floating interest rate swaps in an amount of $100.0 million which fix the interest expense on $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 June 30, 2010, the mark to market value of the interest rate swap was a net $1.6 million liability (June 30, 2009 – $4.7 million net liability).
- APCo's project debt at the St. Leon facility had a balance of $69.6 million as at June 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 June 30, 2010, the mark to market value of the interest rate swap was a net liability of $5.8 million (June 30, 2009 – net liability of $6.0 million).
- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at June 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 six months ended June 30, 2010, cash provided by operating activities exceeded dividends declared by 2.2 times and 1.9 times respectively.

As at June 30, 2010, APUC had cash on hand of $2.4 million and $25.4 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 $252.5 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 nine 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 June 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 second 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 June 30, 2010.

Millions of dollars (except per share amounts)	**3rd Quarter 2009**	**4th Quarter 2009**	**1st Quarter 2010**	**2nd Quarter 2010**
Revenue	$ 45.1	$ 43.4	$ 45.9	$ 42.7
Net earnings /(loss)	13.1	(1.4)	3.5	(2.2)
Net earnings / (loss) per share/trust unit	0.17	(0.03)	0.04	(0.2)
Total Assets	925.7	1,013.4	966.2	983.2
Long term debt*	445.4	439.9	434.0	446.7
Dividend/distribution per share/trust unit	0.06	0.06	0.06	0.06

	3rd Quarter 2008	4th Quarter 2008	1st Quarter 2009	2nd Quarter 2009
Revenue	$ 55.1	$ 56.5	$ 52.2	$ 46.5
Net earnings / (loss)	(4.4)	(21.1)	4.2	15.3
Net earnings / (loss) per trust unit	(0.06)	(0.27)	0.05	0.20
Total Assets	962.7	978.5	974.2	952.4
Long term debt*	460.9	462.9	457.6	456.2
Distribution per trust unit	0.23	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 $42.8 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 gains and losses on financial instruments due to APUC's adoption of Section 3855 and the discontinuation of hedge accounting under Section 3865.

Changes in Accounting Policies

APUC's accounting policies are described in Note 1 to the interim Consolidated Financial Statements for the period ended June 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, 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"). During the quarter it became clear that rate regulated accounting would not be available for publicly accountable enterprises in Canada reporting under IFRS. APUC is an existing SEC registrant and also has a significant and growing portion of its business in regulated utilities. As a result APUC has three alternatives that it is evaluating with respect to the accounting framework under which it is able to prepare its financial statements.

1) **Adopt IFRS**

   Under this option, APUC could commence reporting under IFRS effective January 1, 2011. As previously disclosed and noted below, APUC continues to make significant progress in connection with preparations for conversion to IFRS. If this option is selected, based on progress to date, APUC will be in a position to report under IFRS in accordance with the timeframe required by all publicly accountable enterprises in Canada. This option would currently not permit continued rate regulated accounting.

2) **Continued reporting under Canadian GAAP**

   The IASB is working on a project to address the recognition, measurement and disclosure of regulatory assets and regulatory liabilities under IFRS. The conclusions of the project are not expected to be finalized in time for Canada's transition to IFRS. On July 28th, 2010, the Accounting Standard Board of the Canadian Institute of Chartered Accountants issued an exposure-draft proposing that qualifying entities with rate-regulated activities be permitted, but not required, to continue applying Canadian GAAP for an additional two years. A final decision in regards to the exposure-draft is expected in the fall and if approved would allow APUC to defer adoption of IFRS until 2013.

3) **Reporting under US GAAP**

   As an SEC registrant APUC currently reports under US GAAP in the U.S. US GAAP reporting is permitted by Canadian securities laws and the TSE for companies subject to reporting obligations under US securities laws. This option would result in minimal changes having to be made to its financial statements as there are few differences between US GAAP and current Canadian GAAP.

APUC is currently evaluating the three options and assessing which of the three accounting framework options would provide its shareholders and other interested readers of its financial statements the most useful basis for financial reporting.

Changeover to International Financial Reporting Standards

APUC has continued to make progress with respect to its preparations for the changeover to IFRS. While the exact impact on APUC's financial statements of moving to IFRS is not completely known at this time; APUC conducted a high level diagnostic and qualitative assessment of its operations in order to identify the main areas where IFRS conversion will have the largest impact.

Based on the analysis to date, areas of potential change may involve, but may not be limited to, the following:

- the valuation of property, plant and equipment and the requirement to record and amortize on the basis of material components,
- business combinations,
- translation of financial statements of foreign operations,
- consolidation,
- leases,
- assessment and accounting treatment of some income tax related items,
- financial statement disclosures which tend to be more comprehensive under IFRS

Experience in other jurisdictions has shown that earnings may tend to become more volatile and there will be an increase in the volume and complexity of financial disclosures.

APUC has developed a conversion plan in order to be prepared for the conversion and to minimize any disruption the conversion may cause. APUC's conversion plan, detailed below, addresses matters including detailed assessment of the effect of IFRS on its financial statements preparation, information systems requirements, internal control over financial reporting ("ICOFR") as well as disclosure controls and procedures ("DC&P"), in addition to training and other related business matters. This conversion plan is subject to change as a result of ongoing and subsequent changes to IFRS standards and interpretations. APUC's Audit Committee is involved with this process and is being provided formal updates on a quarterly basis and as required.

Financial Statement Preparation
APUC has begun to prepare IFRS format financial statements to highlight note disclosure differences between IFRS and Canadian GAAP. Following the company wide high-level analysis, detailed analyses are being performed for each of the main areas of differences. At that point, detailed accounting differences are identified and quantified, the impact on information systems and the need for training are assessed and the resulting changes to ICOFR and DC&P are evaluated, designed and implemented area by area. The company-wide impact will then be summarized and finalized. The adjustments that arise on retrospective conversion from Canadian GAAP to IFRS will be recognized directly in opening retained earnings.

Four key areas of differences are described below.

Property, Plant & Equipment ("PP&E")
The plan focuses initially on its greatest area of required effort being PP&E. IFRS and Canadian GAAP contain the same basic principles for PP&E; however, there are some differences. Specifically, there may be changes in accounting for PP&E relating to:

- Component accounting, including periodic overhaul costs (power generation)
- Rate-regulated entities

IFRS requires PP&E to be measured at cost in accordance with IFRS, breaking down material items into components and amortizing each one separately. This method of componentizing PP&E may result in an increased number of component parts for the power generation facilities that are separately recorded and depreciated and, as a result, may impact the calculation of depreciation expense. Significant progress has been made in this area.

In April 2010, the IASB decided to include in the Annual Improvements 2008-2010 cycle an amendment to IFRS 1 *First-time Adoption of International Financial Reporting Standards* regarding the use of a previous GAAP carrying amount as deemed cost for property, plant and equipment and intangible assets used in operations subject to rate regulation. APUC intends to avail itself of this IFRS 1 exemption which will allow Liberty Water to use the carrying amount of PP&E reported under Canadian GAAP as at December 31, 2009 as its deemed cost at the date of transition to IFRSs.

In addition, IFRS permits PP&E to be measured at fair value or amortized cost. In this regard, APUC expects to continue to reflect PP&E at amortized costs.

Impairment of Long-Lived Assets
Canadian GAAP impairment testing for long-lived assets involves two steps, the first of which compares the asset carrying values (as calculated for IFRS purposes) with undiscounted future cash flows to determine whether impairment exists. If the carrying value exceeds the amount recoverable on an undiscounted basis, then the carrying values are written down to estimated fair value. IFRS uses a one-step approach for both testing for and measurement of impairment, with an asset carrying value compared directly with the higher of fair value less costs to sell and value in use (which uses discounted future cash flows). This may result in more frequent write-downs where carrying values of assets were previously considered recoverable under Canadian GAAP on an undiscounted cash flow basis, but could not be supported on a discounted cash flow basis. The work in this area will be performed once the carrying value of assets, namely PP&E, under IFRS has been assessed and finalized.

Business Combinations
No significant immediate impact on the financial statements is anticipated on adoption of IFRS as APUC expects to take advantage of the IFRS 1 exemption which avoids the requirement to retrospectively restate all business combinations prior to the date of transition to IFRS, subject to certain balance sheet adjustments. Beginning January 1, 2010, a number of differences between IFRS and Canadian GAAP will affect the accounting for APUC's business acquisitions. Under IFRS, all assets and liabilities of an acquired business are recorded at fair value. Estimated obligations for contingent considerations and contingencies are also recorded at fair value at the acquisition date.

Under IFRS, acquisition-related costs are expensed as incurred. Under Canadian GAAP, acquisition-related costs form part of the consideration paid for the acquisition and contingent considerations are recorded as part of the cost of the acquisition when the contingency is resolved and the consideration is issued or becomes issuable. The treatment of acquisition-related costs is expected to represent a key difference between IFRS and Canadian GAAP in regards to the acquisition of

Tinker and Galveston which took place in Q1 2010 and an electrical generation utility which is expected to close before the end of 2010.

Translation of Foreign Currency Operations

IFRS requires each entity to determine its functional currency using a hierarchy of criteria. Under Canadian GAAP, prior to January 1, 2010, the power generation facilities operating in the U.S. were considered integrated operations and translated into Canadian dollars using the temporal method whereby current rates of exchange are used for monetary assets and liabilities, historical rates of exchange for non-monetary assets and liabilities and average rates of exchange for revenues and expenses, except amortization which is translated at the rates of exchange applicable to the related assets. Gains and losses resulting from these translation adjustments are included in income. Under IFRS, APUC expects that its U.S. operations will all be considered to have a U.S. dollar functional currency. The assets and liabilities of these operations will be translated into Canadian dollars at the rate prevailing at the balance sheet date while revenues and expenses to be converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the operations of self-sustaining operations will be reported as a component of Other Comprehensive Income in the Consolidated Statement of Comprehensive Income. Effective January 1, 2010, the power generation facilities operating in the U.S. are accounted for as self-sustaining operations under Canadian GAAP and are prospectively translated into Canadian dollars using the current rate method. As the current rate method is essentially the same as the translation method used under IFRS, APUC no longer expects any translation differences upon transition to IFRS.

Activity	Milestone/Deadlines	Progress to date
Identify relevant differences between IFRS and Canadian GAAP, design and implement solutions.	Assessment and quantification of the significant effects of the changeover completed by approximately the third quarter of 2010.	Fundamental IFRS/GAAP differences identified.
Evaluate and select one-time and ongoing accounting policy alternatives.	Final selection of accounting policy alternatives by the fourth quarter of 2010.	Assessment and quantification is underway.
Quantify the effects of changeover to IFRS.		
Prepare draft IFRS format financial statements.		Draft IFRS format financial statements presented to the Audit Committee.

Financial Reporting Expertise
APUC hired subject matter experts to co-ordinate, manage and execute on the changeover process. APUC's key personnel and Audit Committee members continue to invest in various training courses with regard to IFRS rules and the impact these rules will have on APUC's reporting requirements. Internal training continues to be developed for the Audit Committee and personnel affected by IFRS.

Activity	Milestone/Deadlines	Progress to date
Define and introduce appropriate level of IFRS expertise.	Audit Committee training in advance of accounting policy decisions. Training for accounting and operations as each area is rolled out, no later than Q4 2010.	Key areas training presented to Audit Committee members in 2009 and 2010. Initial property, plant & equipment training presented to accounting staff. Other areas are in progress.

Information Technology ("IT") Systems
APUC continues to assess the expected impact of the conversion to IFRS on the IT systems. APUC does not expect that the conversion to IFRS will require major new IT system implementations.

Activity	Milestone/Deadlines	Progress to date
Identify and address changes required to IT systems. Evaluate and select methods to address need for dual record-keeping during 2010 for comparative and budget planning purposes in 2011.	Changes to significant systems and dual reporting completed for the third quarter of 2010.	IT assessment for the critical areas is under way.

Internal Controls
APUC continuously assesses the expected impact of the conversion to IFRS on internal control over financial reporting (“ICOFR”) and disclosure controls and procedures (“DC&P”). No significant changes have been required to internal controls to-date. Investor relations will be updated once the impacts of the transition to IFRS are better understood which will most likely be sometime in 2010 or 2011.

Activity	Milestone/Deadlines	Progress to date
Identify and address changes required to ICOFR and DC&P to financial systems. Assess design and effectiveness implications.	Changes to significant systems assessed and designed by Q3 2010. Effectiveness of internal controls signed off by Q4 2010.	ICOFR & DC&P assessment for the critical areas is under way.

Business Matters
APUC’s Facilities mature on January, 14, 2011. Discussions with the lenders have been initiated. APUC expects to be able to negotiate any required amendments to covenants that may be impacted by the conversion to IFRS during the renewal process.

Activity	Milestone/Deadlines	Progress to date
Identify and address changes required to business matters such as bank covenants, compensation, internal reporting, budgeting and rate case filings.	Changes to significant systems and dual reporting completed for the fourth quarter of 2010.	Bank discussions have been initiated.

Interim Consolidated Balance Sheets

(Unaudited) (thousands of Canadian dollars)

	June 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash	$ 2,396	$ 2,796
Short term investments	-	40,010
Accounts receivable	23,435	20,484
Prepaid expenses	3,113	4,674
Income tax receivable	345	1,143
Current portion of future tax asset	13,329	14,566
Current portion of notes receivable	534	521
	43,152	84,194
Long-term investments and notes receivable	29,775	24,029
Future non-current income tax asset	62,761	61,219
Property, plant and equipment (note 3)	756,766	749,350
Intangible assets (note 3)	81,425	85,929
Restricted cash	4,233	4,316
Deferred financing costs	175	200
Other assets	4,871	4,176
	$ 983,158	$ 1,013,413
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 29,723	$ 33,219
Dividends payable	5,655	1,857
Income taxes payable	318	5
Current portion of long-term liabilities (note 5)	106,274	3,360
Current portion of other long-term liabilities	1,095	1,025
Current portion of derivative liabilities (notes 3 and 12)	5,899	5,775
Current portion of deferred credits	10,663	10,500
Future income tax liability	641	913
	160,268	56,654
Long-term liabilities	146,154	241,412
Convertible debentures	171,075	173,257
Other long-term liabilities	26,671	25,228
Future income tax liability	80,103	79,914
Derivative liabilities (note 12)	4,623	3,920
Deferred credits	36,649	39,379
Shareholders' equity:		
Shareholders' capital (note 6)	795,214	787,037
Deficit	(354,744)	(344,676)
Accumulated other comprehensive loss	(82,855)	(48,712)
	357,615	393,649
	$ 983,158	$ 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 June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Revenue:				
Energy sales	**$ 31,745**	$ 32,373	**$ 68,262**	$ 69,874
Waste disposal fees	**90**	3,178	**1,007**	6,861
Water reclamation and distribution	**9,503**	9,932	**17,753**	19,604
Other revenue	**1,338**	1,066	**1,541**	2,374
	42,676	46,549	**88,563**	98,713
Expenses				
Operating	**22,312**	25,014	**48,371**	54,575
Amortization of property, plant and equipment	**8,957**	9,531	**18,024**	19,360
Amortization of intangible assets	**2,634**	1,822	**4,896**	3,660
Management costs (note 7)	**-**	212	**-**	425
Administrative expenses	**2,990**	2,544	**5,905**	4,931
(Gain) / loss on foreign exchange	**404**	(1,892)	**366**	(1,315)
	37,297	37,231	**77,562**	81,636
Earnings before undernoted	**5,379**	9,318	**11,001**	17,077
Interest expense	**6,166**	5,143	**12,413**	10,657
Interest, dividend income and other income	**(1,337)**	(1,173)	**(2,360)**	(2,285)
(Gain) / loss on derivative financial instruments (note 12)	**3,052**	(12,201)	**2,140**	(8,703)
	7,881	(8,231)	**12,193**	(331)
Earnings from operations before income taxes and minority interest	**(2,502)**	17,549	**(1,192)**	17,408
Income tax expense (recovery)				
Current	**269**	262	**436**	463
Future	**(681)**	389	**(3,054)**	(4,804)
	(412)	651	**(2,618)**	(4,341)
Minority interest in earnings of subsidiaries	**146**	1,596	**211**	2,204
Net earnings (loss)	**$ (2,236)**	$ 15,302	**$ 1,215**	$ 19,545
Basic net (loss) / earnings per share (note 8)	**$ (0.02)**	$ 0.20	**$ 0.01**	$ 0.25
Diluted net (loss) / earnings per share (note 8)	**$ (0.02)**	$ 0.20	**$ 0.01**	$ 0.25

See accompanying notes to interim consolidated financial statements

Interim Consolidated Statements of Cash Flows

(Unaudited) (thousands of Canadian dollars)

	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Cash provided by (used in):				
Operating Activities:				
Net earnings (loss)	**$ (2,236)**	$ 15,302	**$ 1,215**	$ 19,545
Items not affecting cash:				
Amortization of property, plant and equipment	**8,960**	9,531	**18,024**	19,360
Amortization of intangible assets	**2,634**	1,822	**4,896**	3,660
Other amortization	**551**	217	**1,361**	478
Distributions received in excess of equity income	**(76)**	649	**646**	1,489
Future income taxes / (recovery)	**(681)**	389	**(3,054)**	(4,804)
Unrealized (gain) / loss on derivative financial instruments	**1,634**	(13,592)	**(2,571)**	(11,674)
Minority interest	**146**	1,596	**211**	2,204
Unrealized foreign exchange (gain) / loss on long-term debt	**582**	(1,661)	**215**	(890)
	11,514	14,253	**20,943**	29,368
Changes in non-cash operating working capital (note 10)	**1,259**	(4,871)	**978**	(6,285)
	12,773	9,382	**21,921**	23,083
Financing Activities:				
Cash dividends / distributions (note 9)	**(5,625)**	(4,677)	**(7,489)**	(9,341)
Cash distributions to non-controlling interest (notes 7 and 9)	**(146)**	(211)	**(211)**	(470)
Trustee loans	**-**	-	**-**	6
Deferred financing costs	**(91)**	(35)	**(91)**	(52)
Increase in long-term liabilities	**42,000**	11,500	**54,500**	14,000
Decrease in long-term liabilities	**(32,212)**	(7,655)	**(47,615)**	(18,575)
Decrease (increase) in other long-term liabilities	**48**	620	**175**	625
	3,974	(458)	**(731)**	(13,807)
Investing Activities:				
Decrease / (increase) in restricted cash	**33**	(162)	**125**	(93)
Decrease in short-term investment	**-**	-	**40,010**	-
Increase in other assets	**(792)**	(1,727)	**(1,134)**	(1,728)
Receipt of principal on notes receivable	**100**	92	**200**	256
Proceeds from liquidation of Highground assets (note 3(c))	**-**	302	**170**	302
Increase in long term investments and notes (note 4)	**(6,565)**	-	**(6,565)**	-
Net additions to property, plant and equipment	**(7,829)**	(1,242)	**(11,988)**	(6,896)
Acquisitions of operating entities (note 3)	**(24)**	(50)	**(42,402)**	(50)
	(15,077)	(2,787)	**(21,584)**	(8,209)
Effect of exchange rate differences on cash	**(29)**	(125)	**(6)**	(92)
Increase / (decrease) in cash	**1,641**	6,012	**(400)**	975
Cash, beginning of the period	**755**	865	**2,796**	5,902
Cash, end of the period	**$ 2,396**	$ 6,877	**$ 2,396**	$ 6,877
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest expense	**$ 5,871**	$ 4,163	**$ 9,130**	$ 10,073
Cash paid during the period for income taxes	**$ 39**	$ 819	**$ 125**	$ 937

See accompanying notes to interim consolidated financial statements

Interim Consolidated Statement of Deficit

(Unaudited) (thousands of Canadian dollars)

	Three months ended June 30,		Six months ended June 30,	
	2010	**2009**	**2010**	**2009**
Balance, beginning of period	**$ (346,822)**	$ (359,090)	**$ (344,676)**	$ (358,669)
Net earnings (loss)	**(2,236)**	15,302	**1,215**	19,545
Dividends/Distributions (note 9)	**(5,686)**	(4,677)	**(11,283)**	(9,341)
Balance, end of period	**$ (354,744)**	$ (348,465)	**$ (354,744)**	$ (348,465)

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 June 30,		Six months ended June 30,	
	2010	**2009**	**2010**	**2009**
Net (loss) earnings	**$ (2,236)**	$ 15,302	**$ 1,215**	$ 19,545
Other comprehensive loss:				
Forward exchange contracts settled in the period	**-**	(729)	**-**	(1,413)
Translation of self sustaining foreign operations	**12,127**	(13,556)	**3,462**	(8,600)
Other comprehensive income (loss)	**12,127**	(14,285)	**3,462**	(10,013)
Total comprehensive income (loss)	**$ 9,891**	$ 1,017	**$ 4,677**	$ 9,532
Accumulated other comprehensive loss:				
Balance, beginning of the period	**$ (94,982)**	$ (17,170)	**$ (48,712)**	$ (21,442)
Translation of self sustaining foreign operations due to accounting change (note 2)	**-**	-	**(37,605)**	-
Other comprehensive loss (income)	**12,127**	(14,285)	**3,462**	(10,013)
Balance, end of the period	**$ (82,855)**	$ (31,455)	**$ (82,855)**	$ (31,455)

See accompanying notes to interim consolidated financial statements

Notes to the Unaudited Interim Consolidated Financial Statements

Six months ended June 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 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 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 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.

b) 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 preliminarily allocated to net assets acquired as follows:

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

c) 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.

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 June 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 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 six months ended June 30, 2010, APUC received $nil (2009 - $nil) and $170 (2009 - $nil) 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 $2,350. 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 Investments

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 twelve 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.

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 period 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 June 30, 2010, the outstanding amount due on the Facilities of $102,792 has been recorded within the current portion of long-term liabilities on the consolidated balance sheet. This amount drawn at June 30, 2010 includes U.S. $20,000 in U.S. funds.

6. Shareholders' capital

Shareholders' capital consists of the following:

	Three months ended June 30,		Six months ended June 30,	
	2010	**2009**	**2010**	**2009**
Balance of shares/units, beginning of period	$ 784,021	$ 725,106	$ 781,274	$ 721,953
Issued on conversion of Algonquin (AirSource) Power LP exchangeable units	-	719	-	3,872
Conversion of convertible debentures, net of costs	712	-	3,290	-
Amounts received in connection with the Highground transaction	-	302	170	302
Issuance pursuant to management internalization	4,763	-	4,763	-
Balance of shares/units, end of period	789,496	$ 726,127	$ 788,977	$ 726,127
Trustee Loans	-	(211)	-	(211)
Equity component of convertible debentures	5,718	479	6,237	479
Shareholders' capital	795,214	$ 726,395	795,214	$ 726,395

During the six month period, $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 June 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 $4,763 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 June 30, 2010	2009	Six months ended June 30, 2010	2009
Common shares/units, beginning of period	93,745,244	77,906,109	93,064,120	77,574,372
Issued on conversion of Algonquin (AirSource) Power LP exchangeable units	-	75,853	-	407,590
Conversion of convertible debentures	174,565	-	855,689	-
Issued pursuant to management internalization	1,180,180	-	1,180,180	-
Common shares/units, end of period	95 099,989	77,981,962	95,099,989	77,981,962

Stock Option Plan

On June 23, 2010, the Company's shareholders voted in favor of establishing a stock option plan (the 'Plan') to encourage ownership of the Company's common shares by its 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. As of June 30, 2010, the Company has not granted any options under the Plan.

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 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 six months ended June 30, 2010, APMI was not paid a management fee. For the three and six months ended June 30, 2009, APMI was paid on a cost recovery basis for all costs incurred and charged $212 and $425 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 six months ended June 30, 2010 were $81 (2009 - $86) and $163 (2009 - $168) respectively.

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. During the three and six months ended June 30, 2010, APUC incurred costs in connection with the use of the aircraft of $60 (2009 - $60) and $208 (2009 - $140) respectively and amortization expense related to the advance against expense reimbursements of $6 (2009 - $17) and $63 (2009 - $73) 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 $87 (2009 - $103) and $126 (2009 - $157) for the three and six months ended June 30, 2010 respectively.

APMI is entitled to 50% of the cash flow above 15% return on investment for the BCI project pursuant to its project management contract. During the three and six months ended June 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 June 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. No expenses were incurred in the three and six months ended June 30, 2010 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.

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

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 June 30,		**Six months ended June 30,**	
	2010	**2009**	**2010**	**2009**
Weighted average common shares/units – basic	93,901,732	77,931,448	93,535,959	77,815,293
Trust units issuable on conversion of exchangeable units	-	1,677,880	-	1,796,315
Weighted average shares/units – diluted	93,901,732	79,609,328	93,535,959	79,611,608

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 six months ended June 30, 2010 and 2009. At June 30, 2010, the Company had 15,551,838 shares potentially issuable upon conversion of the convertible debentures.

9. Cash 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 six month periods ended June 30, 2010, APUC declared cash dividends to shareholders totaling $5,686 (2009 - $4,677) and $11,283 (2009 - $9,341) respectively or $0.06 per share (2009 - $0.06 per unit) and $0.12 per share (2009 - $0.12 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 six months ended June 30, 2010 were $nil. Total distributions to the Unitholders of the Algonquin (Airsource) Power LP exchangeable units for the three and six months ended June 30, 2009 were $98 and $208 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 compromised of the following:

	Three months ended June 30, 2010	2009	Six months ended June 30, 2010	2009
Accounts receivable	$ 2,385	$ 1,689	$ (2,959)	$ (244)
Income tax receivable	5	178	797	156
Prepaid expenses	840	(1,212)	1,560	(802)
Accounts payable and accrued liabilities	(2,288)	(5,025)	1,268	(4,982)
Current income tax liability	317	(501)	312	(413)
Change in non cash working capital	$ 1,259	$ (4,871)	$ 978	$ (6,285)

11. Segmented Information

APUC has two broad operating segments: Algonquin Power which owns and operates 45 renewable energy facilities and 14 high efficiency thermal energy facilities representing more than 450 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.

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 June 30, 2010	2009	Six months ended June 30, 2010	2009
Revenue				
Canada	$ 16,408	$ 20,165	$ 33,951	$ 42,017
United States	$ 26,268	26,384	$ 54,612	56,696
	$ 42,676	$ 46,549	$ 88,563	$ 98,713

	June 30, 2010	June 30, 2009
Property, plant and equipment		
Canada	$ 473,530	$ 453,482
United States	$ 283,236	329,765
	$ 756,766	$ 783,247
Intangible assets		
Canada	$ 45,896	$ 50,232
United States	$ 35,529	$ 42,021
	$ 81,425	$ 92,253
Other assets		
Canada	$ 860	$ 1,767
United States	$ 4,010	$ 1,702
	$ 4,871	$ 3,469

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.

Three months ended June 30, 2010

	Power Generation & Development			Liberty Water	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	19,974	11,771	31,745	-	-	31,745
Waste disposal fees	-	90	90	-	-	90
Water reclamation and distribution	-	-	-	9,503	-	9,503
Other revenue	997	341	1,338	-	-	1,338
Total revenue	20,971	12,202	33,173	9,503	-	42,676
Operating expenses	6,049	10,783	16,832	5,480	-	22,312
	14,922	1,419	16,341	4,023	-	20,364
Other administration costs	(685)	(306)	(991)	(899)	(1,100)	(2,990)
Foreign exchange gain	-	-	-	-	(404)	(404)
Interest expense	(1,676)	(235)	(1,911)	(452)	(3,803)	(6,166)
Interest, dividend and other income	264	131	395	-	942	1,337
Gain / (loss) on derivative financial instruments	(2,038)	-	(2,038)	-	(1,014)	(3,052)
Amortization of property, plant and equipment	(5,871)	(1,341)	(7,212)	(1,745)	-	(8,957)
Amortization of intangible assets	(1,770)	(693)	(2,463)	(171)	-	(2,634)
Net earnings / (loss) before income taxes and minority interest	3,146	(1,025)	2,121	756	(5,379)	(2,502)
Property, plant and equipment	404,114	179,150	583,264	173,139	363	756,766
Intangible assets	31,852	25,112	56,964	24,461	-	81,425
Total assets	459,636	221,915	681,551	208,921	92,686	983,158
Capital expenditures	679	6,097	6,776	991	62	7,829
Acquisition of operating entities	-	-	-	-	-	-

	Six months ended June 30, 2010					
	Power Generation & Development			Liberty Water	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	42,192	26,070	68,262	-	-	68,262
Waste disposal fees	-	1,007	1,007	-	-	1,007
Water reclamation and distribution	-	-	-	17,753	-	17,753
Other revenue	997	544	1,541	-	-	1,541
Total revenue	43,189	27,621	70,810	17,753	-	88,563
Operating expenses	14,174	23,289	37,463	10,908	-	48,371
	29,015	4,332	33,347	6,845	-	40,192
Other administration costs	(1,830)	(851)	(2,681)	(1,264)	(1,960)	(5,905)
Foreign exchange gain	-	-	-	-	(366)	(366)
Interest expense	(3,509)	(452)	(3,961)	(882)	(7,570)	(12,413)
Interest, dividend and other income	402	270	672	11	1,677	2,360
Gain / (loss) on derivative financial instruments	(2,268)	-	(2,268)	-	128	(2,140)
Amortization of property, plant and equipment	(10,253)	(4,244)	(14,497)	(3,527)	-	(18,024)
Amortization of intangible assets	(3,171)	(1,389)	(4,560)	(336)	-	(4,896)
Net earnings / (loss) before income taxes and minority interest	8,386	(2,334)	6,052	847	(8,091)	(1,192)
Property, plant and equipment	404,114	179,150	583,264	173,139	363	756,766
Intangible assets	31,852	25,112	56,964	24,461	-	81,425
Total assets	459,636	221,915	681,551	208,921	92,686	983,158
Capital expenditures	943	9,932	10,875	1,036	77	11,988
Acquisition of operating entities	40,363	-	40,363	2,039	-	42,402

	Three months ended June 30, 2009					
	Power Generation & Development			Liberty Water	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	$ 17,462	$ 14,911	$ 32,373	$ -	$ -	$ 32,373
Waste disposal fees	-	3,178	3,178	-	-	3,178
Water reclamation and distribution	-	-	-	9,932	-	9,932
Other revenue	-	1,066	1,066	-	-	1,066
Total revenue	17,462	19,155	36,617	9,932	-	46,549
Operating expenses	5,416	13,707	19,123	5,891	-	25,014
	12,046	5,448	17,494	4,041	-	21,535
Other administration costs	(1,177)	(662)	(1,839)	(441)	(476)	(2,756)
Foreign exchange gain	-	-	-	-	1,892	1,892
Interest expense	(1,756)	(270)	(2,026)	(482)	(2,635)	(5,143)
Interest, dividend and other income	308	124	432	(38)	779	1,173
Gain / (loss) on derivative financial instruments	3,257	(285)	2,972	286	8,943	12,201
Amortization of property, plant and equipment	(4,180)	(3,294)	(7,474)	(2,057)	-	(9,531)
Amortization of intangible assets	(659)	(979)	(1,638)	(184)	-	(1,822)
Net earnings / (loss) before income taxes and minority interest	7,839	82	7,921	1,125	8,503	17,549
Property, plant and equipment	$ 404,928	$ 185,971	$590,899	$ 192,348	$ -	$ 783,247
Intangible assets	31,939	32,402	64,341	27,912	-	92,253
Total assets	553,801	162,514	716,315	228,375	7,667	952,357
Capital expenditures	207	920	1,127	16	99	1,242
Acquisition of operating entities	-	-	-	50	-	50

	Six months ended June 30, 2009					
	Power Generation & Development			Liberty Water	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	$ 36,425	$ 33,449	$ 69,874	$ -	$ -	$ 69,874
Waste disposal fees	-	6,861	6,861	-	-	6,861
Water reclamation and distribution	-	-	-	19,604	-	19,604
Other revenue	-	2,374	2,374	-	-	2,374
Total revenue	36,425	42,684	79,109	19,604	-	98,713
Operating expenses	10,728	31,850	42,578	11,997	-	54,575
	25,697	10,834	36,531	7,607	-	44,138
Other administration costs	(2,905)	(1,534)	(4,439)	(917)	-	(5,356)
Foreign exchange gain	-	-	-	-	1,315	1,315
Interest expense	(3,768)	(611)	(4,379)	(1,121)	(5,157)	(10,657)
Interest, dividend and other income	552	256	808	(37)	1,514	2,285
Gain / (loss) on derivative financial instruments	3,047	(664)	2,383	155	6,165	8,703
Amortization of property, plant and equipment	(8,375)	(6,598)	(14,973)	(4,387)	-	(19,360)
Amortization of intangible assets	(1,317)	(1,951)	(3,268)	(392)	-	(3,660)
Net earnings / (loss) before income taxes and minority interest	12,931	(268)	12,663	908	3,837	17,408
Property, plant and equipment	$ 404,928	$ 185,971	$590,899	$ 192,348	$ -	$ 783,247
Intangible assets	31,939	32,402	64,341	27,912	-	92,253
Total assets	553,801	162,514	716,315	228,375	7,667	952,357
Capital expenditures	505	1,974	2,479	4,318	99	6,896
Acquisition of operating entities	-	-	-	50	-	50

12. Derivative instruments

As of June 30, 2010, the fair value of derivatives liabilities is as follows:

	June 30, 2010	December 31, 2009
Derivative liabilities:		
Interest Rate SWAP – St Leon	$ 5,819	$ 4,966
Interest Rate SWAP – revolving credit facility	1,607	3,260
Foreign exchange forward contracts	1,612	1,469
Energy forward purchase contracts	1,484	-
	$ 10,522	$ 9,695
Less: current portion	(5,899)	(5,775)
Long term derivative liabilities	$ 4,623	$ 3,920

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

	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Unrealized loss / (gain) on derivative financial instruments:				
Foreign exchange contracts	$ 1,226	$ (9,042)	$ 143	$ (6,726)
Interest rate swaps	488	(4,550)	(799)	(4,948)
Energy forward purchase contracts	(80)	-	(1,914)	-
Total unrealized loss / (gain) on derivative financial instruments	$ 1,634	$ (13,592)	$ (2,570)	$ (11,674)
Realized loss/(gain) on derivative financial instruments:				
Foreign exchange contracts	$ (293)	$ (2)	$ (425)	$ 509
Interest rate swaps	1,586	1,393	3,182	2,462
Energy forward purchase contracts	125	-	1,953	-
Total realized loss/(gain) on derivative financial instruments	$ 1,418	$ 1,391	$ 4,710	$ 2,971
Loss / (gain) on derivative financial instruments	$ 3,052	$ (12,201)	$ 2,140	$ (8,703)

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 June 30, 2010, Algonquin had U.S. $28,030 in outstanding foreign exchange forward contracts carrying an average rate of $1.016. At June 30, 2010, the fair value of the foreign exchange forward contracts was a $1,612 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 $69,612 as at June 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 June 30, 2010, the fair value of the interest rate swap was a $5,819 liability.

APUC senior revolving credit facility has a balance of $102,792 as at June 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 June 30, 2010, the fair value of this interest rate swap was a $1,607 liability.

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 though the use of short term forward energy hedge contracts. APUC has committed to acquire approximately 25,000 MW-hrs of energy over the next 8 months at an average rate of approximately $75 per MW-hr. The mark to market value of these forward energy hedge contracts at June 30, 2010 was a net liability of $1,484.

13. Comparative figures

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

Notes

Notes

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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.
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