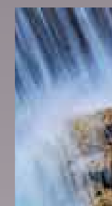
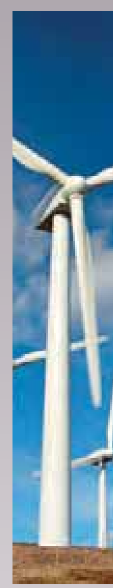
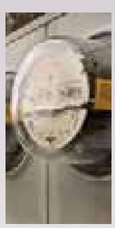
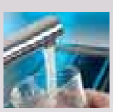
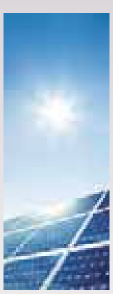
2012 ANNUAL REPORT

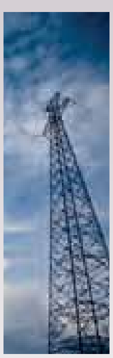












ALGONQUIN
Power & Utilities Corp.

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ALGONQUIN
Power & Utilities Corp.

Algonquin Power & Utilities Corp. owns and operates a $3.0 billion portfolio of diversified regulated and non-regulated utility assets across North America.

Algonquin creates shareholder value through the prudent investment in regulated and non-regulated assets, delivering stable earnings and cash flows coupled with the opportunity for growth.

Toronto Stock Exchange: Common Shares – AQN, Preferred Shares – AQN.PR.A

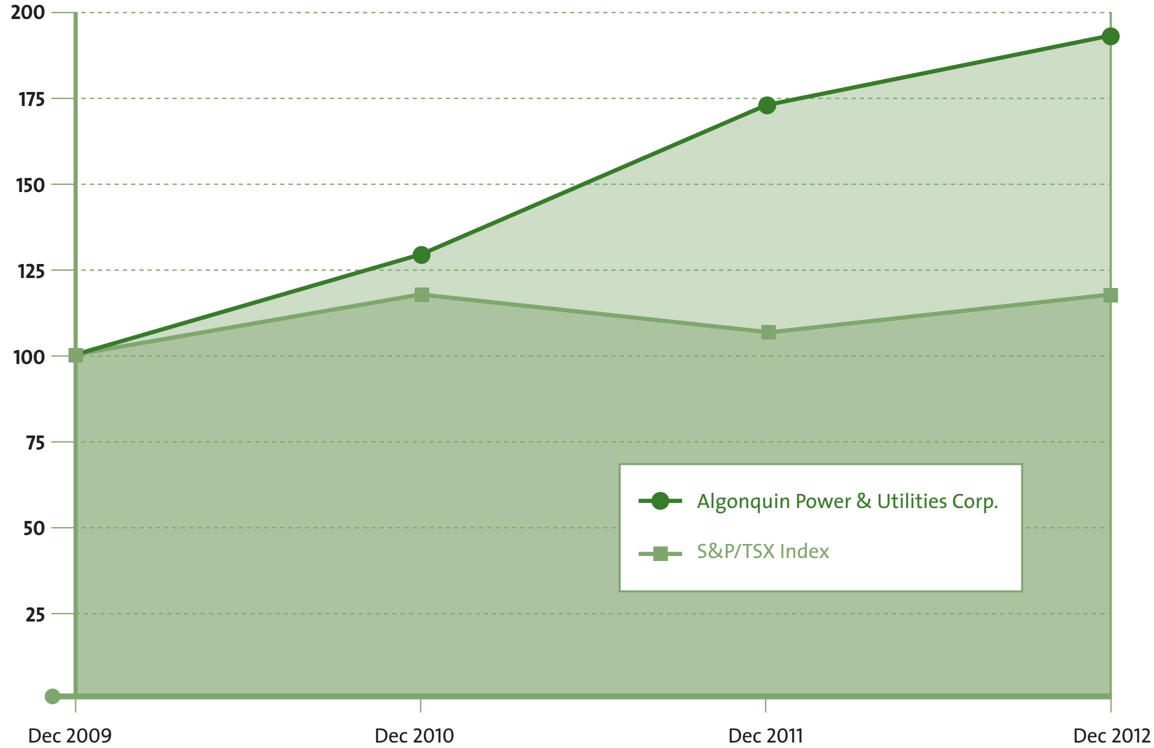
www.AlgonquinPowerandUtilities.com

2012 FINANCIAL HIGHLIGHTS

(in $ millions)	2012	2011	2010	2009
REVENUE				
Power	139.1	148.4	137.1	141.3
Utilities	230.8	122.3	38.0	38.5
Total Revenue	**369.9**	**270.7**	**175.1**	**179.8**
ADJUSTED EBITDA	**106.2**	**103.7**	**74.1**	**75.6**
EARNINGS, FUNDS FROM OPERATIONS AND DIVIDENDS				
Adjusted Funds from Operations	76.9	72.7	41.5	45.5
Per Share	0.52	0.62	0.44	0.57
Adjusted Net Earnings	21.1	38.3	22.8	29.3
Per Share	0.14	0.33	0.24	0.37
Dividends to Shareholders	50.2	32.4	22.8	19.3
Per Share	0.30	0.27	0.24	0.24
BALANCE SHEET DATA				
Total Assets	2,778.2	1,282.6	1,016.9	1,013.4
Long-Term Liabilities (includes current portion)	771.8	455.0	441.7	241.4
Shareholders Equity	1,402.1	552.7	348.9	393.6
Number of Shares Outstanding as of Dec. 31	188,763,486	136,122,780	95,422,778	93,064,120
PROPERTY, PLANT & EQUIPMENT				
Canada	472.3	474.1	466.2	440.5
US	1,690.4	446.0	224.0	268.0
Total	**2,162.7**	**920.1**	**690.2**	**708.5**
RENEWABLE ENERGY PRODUCTION (% OF LONG TERM AVERAGE)	**89%**	**107%**	**90%**	**102%**
UTILITY CUSTOMERS	**337,805**	**122,406**	**73,086**	**71,598**

Please Note: The table above includes Non-GAAP measures. The Company uses adjusted EBITDA, adjusted net earnings, per share adjusted net earnings, adjusted funds from operations, and per share adjusted funds from operations to enhance assessment and understanding of the operating performance of the Company without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions. For full results, users of this document should refer to the Management's Discussion & Analysis, Consolidated Financial Statements, and Notes to the Consolidated Financial Statements, and also see the caution regarding non-GAAP measures on page 14, and applicable section in the Management's Discussion & Analysis.

TOTAL RETURN PERFORMANCE

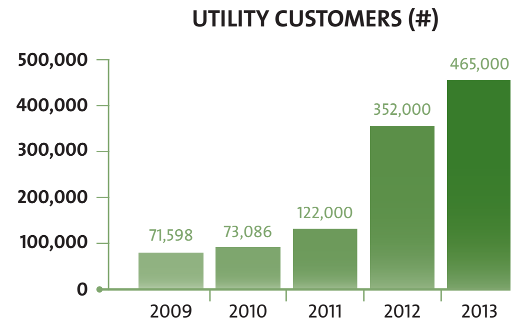


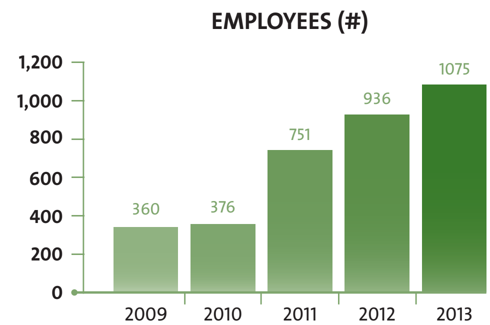
Our focus has never been clearer. With achievement of our 2010 stated target of doubling the size of our business within five years now behind us, we continue to focus on creating shareholder value through prudent expansion of our businesses and a dedication to maximizing Total Shareholder Return.

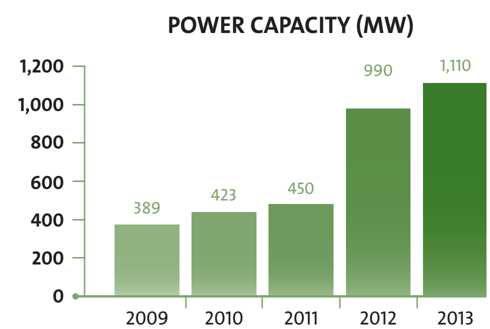
OUR GROWING BUSINESS

Our organization is headed by an experienced executive management team with over 60 years of combined experience in the regulated utility and non-regulated power sectors. We have successfully grown the business over a period of 17 years and now boast annual revenues of over $370 million.

We are continuing to reinforce our leading presence in North America, prudently extending our expertise in the regulated utilities sector and diversifying our non-regulated generation portfolio. Our financial strength, proven long-term strategy and diversified business mix position us for continued success in 2013 and beyond.







2013 data assumes inclusion of committed acquisitions and development projects

OUR NON-REGULATED ELECTRICAL GENERATION UTILITY

Algonquin Power Co., our electric generation subsidiary, generates and sells electrical energy through a diverse portfolio of clean, renewable power generation facilities across North America. We own or have interests in 33 generating facilities representing more than 1,100 MW of installed capacity. Our focus on establishing long term power purchase agreements provides stability and transparency to our economic results. Continuing growth in the business will be realized through the build out of our pipeline of over 350 MW of contracted power development projects representing more than $850 million in potential investment opportunity.

2012 growth achievements:

- Signed a 25 year power purchase agreement with SaskPower for a 177 MW wind facility
- Announced and closed the acquisition of a 60% interest in a 400 MW portfolio of wind generating facilities in Texas, Pennsylvania and Illinois
- Acquired a 109.5 MW wind generating facility in Illinois

Expected 2013 highlights:

- Construction of a 10 MW solar powered generating facility in 2013
- Continuing development of our 350 MW of contracted wind energy generation opportunities

OUR REGULATED DISTRIBUTION UTILITY

Liberty Utilities Co., our U.S. based utility business, provides cost-of-service rate regulated water, natural gas and electric distribution utility services to more than 348,000 customers located in eight states. In 2013, Liberty Utilities Co. will be expanded with the acquisition of Georgia and Massachusetts natural gas distribution utilities serving an additional 117,000 customers. We are committed to expanding this business organically through continued capital investment within each utility and through further acquisitions of high quality water, electricity and natural gas distribution assets.

2012 growth achievements:

- Acquired New Hampshire electricity and natural gas distribution utilities
- Acquired Missouri, Illinois and Iowa natural gas distribution utilities
- Announced acquisition of Arkansas water distribution utility
- Announced acquisition of Georgia natural gas distribution utility

Expected 2013 Highlights:

- Completion of Arkansas and Georgia utility acquisitions
- Acquisition of Massachusetts natural gas distribution utility
- Filing of rate increase request for New Hampshire electricity distribution utility

2012 LETTER TO SHAREHOLDERS

Ian Robertson
CEO

Ken Moore
Chairman of the Board of Directors

The quality and stability of our portfolio of regulated and non-regulated utility assets is a fundamental strength of our company and is central to our value proposition for investors.

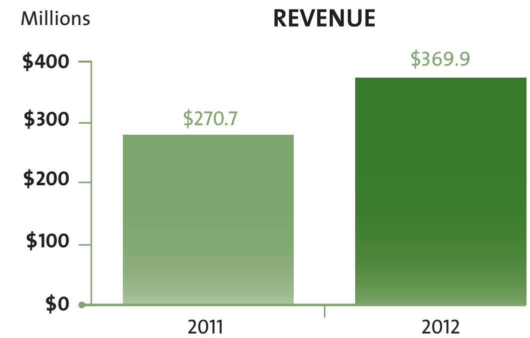
DEAR FELLOW SHAREHOLDERS,

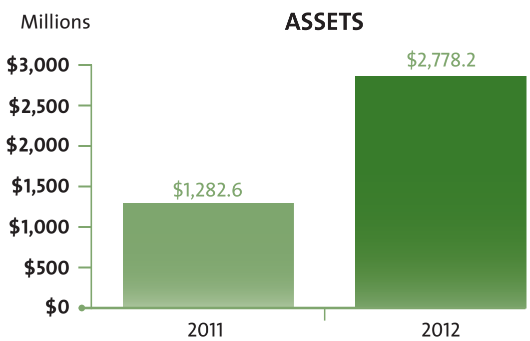
On behalf of everyone at Algonquin Power & Utilities Corp. (the "Company" or "Algonquin"), thank you for investing in us. The team here has been working very hard to earn and maintain the confidence of investors like you and we can assure you that creating long-term value for your investment is foremost in the decisions we make every day.

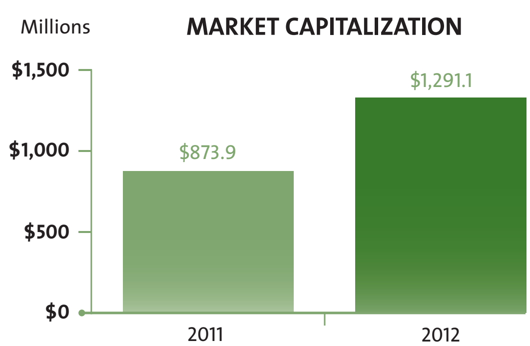
Fiscal 2012 has been a year of significant change, transition and accomplishment for us. While there were the usual highs and lows in 2012, we hope you would agree that our overall report card shows very solid marks. As a result of acquisitions and successful organic growth programs in 2012, we have more than doubled our asset base, increased our annual revenues by over 30% and grown our market capitalization by almost 50% from the end of 2011 compared to the end of 2012.

Moreover, the Company saw attractive total shareholder returns of over 11% through our stable and growing dividend, coupled with capital appreciation which is underpinned by increases in genuine earnings and cash flow arising from the successful execution on our growth strategies.

During the year, our non-regulated utilities division, Algonquin Power Co. ("APCo"), announced several exciting growth milestones. Our business development team closed the acquisition of a 60% interest in a portfolio of 400 MW of U.S. based wind generation, consisting of three facilities – Sandy Ridge (50MW), Minonk (200MW) and Senate (150MW). In addition, our team announced a 25 year power purchase agreement with SaskPower for a 177MW wind power project in Chaplin, Saskatchewan. We kicked off 2013 on a high note with the announcement of additional geographic diversification through the acquisition of a 109.5MW wind power facility in Illinois. 2013 will see further diversification and continued growth through our pipeline of contracted solar projects.







In addition, our regulated utilities group, Liberty Utilities Co. ("Liberty Utilities") strategically increased its utility footprint across the United States. We welcomed the addition of our New Hampshire electric distribution and natural gas distribution utilities following a successful regulatory acquisition approval in New Hampshire as well as the regulated natural gas distribution assets in Missouri, Illinois and Iowa. With our current growth commitments, the customer base served by the Liberty Utilities family will approach nearly half a million customers in 2013.

Our utilities business planning team continues to actively source and evaluate additional opportunities to provide increased per share earnings and cash flow to the organization. In mid-2012 we announced the acquisition of additional water and natural gas utilities in Arkansas and Georgia, bringing approximately 80,000 additional customers to the Liberty Utilities family. These two acquisitions announced in 2012 demonstrate our path to continued growth of the regulated utility business.

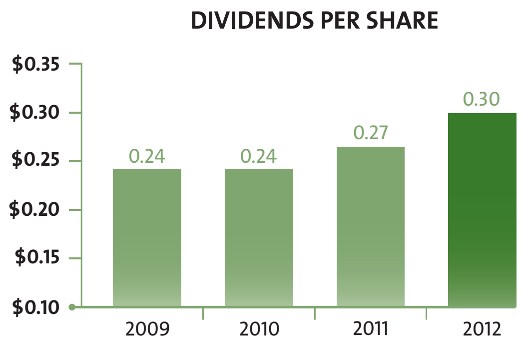
We remain committed in 2013 to deliver continued value accretive growth in both our non-regulated and regulated utility businesses and our development teams are working on the next projects and acquisitions that you will hear about in the near future.

"As a result of acquisitions and successful organic growth programs in 2012, we have more than doubled our asset base, increased our annual revenues by over 30% and grown our market capitalization by almost 50% from the end of 2011 compared to the end of 2012."

Our recent acquisitions and investment initiatives affirmed the growth trajectory of our Company's earnings and cash flows in 2012 and, consequently, the Board of Directors approved an 11% dividend increase to $0.31 per common share annually.

TOTAL SHAREHOLDER RETURN

Our recent acquisitions and investment initiatives affirmed the growth trajectory of our Company's earnings and cash flows in 2012 and, consequently, the Board of Directors approved an 11% dividend increase to $0.31 per common share annually. We believe this dividend increase is consistent with our strategy of delivering total shareholder return comprised of an attractive dividend yield and capital appreciation founded on increased earnings and cash flows.



STRENGTHENING OUR BALANCE SHEET

While we made significant investments in our future, 2012 also saw the results of our efforts to substantially strengthen our balance sheet. In 2012, we added yet another financial instrument to our capital structure through our first issue of $120 million cumulative rate reset preferred shares. The shares have a coupon of 4.5% annually for the initial six-year rate reset period and have been assigned a rating of P-3 and Pfd-3(low) by S&P and DBRS respectively.

In 2012 we also retired our final two series of convertible debentures and as a result, convertible debentures no longer form part of the Algonquin capital structure.

The Company has continued to build upon the investment grade debt financing platforms of both APCo and Liberty through the completion of several new senior unsecured credit facilities. APCo successfully completed a follow-on $150 million 4.8% bond offering (swapped to US$ at 4.4%) to finance our U.S. wind acquisitions. Additionally, Liberty Utilities closed a U.S. $225 million private placement debt financing to partially fund the natural gas and electric distribution utilities in New Hampshire, Missouri, Illinois and Iowa. These financing platforms were carefully designed to provide us with the additional liquidity and financial flexibility needed to facilitate the continued growth of both our regulated and non-regulated utility businesses.

Our relationship with Emera, our largest shareholder, remains strong and they have continued to be an enthusiastic supporter of our growth plans. They have increased their ownership in our Company to 25% as contemplated in our strategic investment agreement. We believe that our strong relationship with Emera provides strategic business development support and is an efficient way to raise equity.

OUR CHALLENGES

While we certainly celebrate our accomplishments, we also need to recognize 2012 posed some challenges, such as historically low hydrology, continued depressed power prices in the U.S., longer than expected regulatory processes, and the end of the Region of Peel's waste supply contract with our energy from waste facility. In facing these challenges we take comfort in the knowledge that this is not the first time we have endured difficult circumstances and we remain confident that our diversification and contingency planning will ensure we can continue to navigate our way successfully.

To ensure we fully capitalize on our opportunities, we are enhancing our risk management practices to ensure that the Company's risks and related exposures are consistent with our business objectives and risk tolerance. We view ourselves as a risk-focused, socially and environmentally sustainable organization committed to investing in our people, our assets, our businesses and ultimately, our future.

PRIORITIES FOR 2013

Our priority for 2013 is to continue to build on the growth momentum we have generated over the past few years. Our 2013 scorecard targets reflect expected contributions from new operations, such as our solar powered electrical generation project in Cornwall, Ontario, growing discretionary cash flow and further strengthening our stable base of earnings.

Value accretive growth through organic expansion, greenfield power project development and attractive acquisitions continues as a primary focus in 2013. Our regulated and non-regulated business development teams are seeking opportunities that are consistent with our strategy and meet our return expectations. Our Board of Directors continues to provide valuable governance and oversight of the Company in the review and balancing of the many opportunities that come our way.

As a Company, we believe that identifying and managing risk is a key component of success across our regulated and unregulated utilities businesses and fundamental to effective corporate governance. Our Company has adopted a philosophy aimed at maximizing business success and shareholder value by effectively balancing risk and reward. We have a clear framework for identifying and managing risk, both at an operational and strategic level. Strengthening our disciplined approach to managing risk and optimizing our portfolio will be a key theme for 2013.

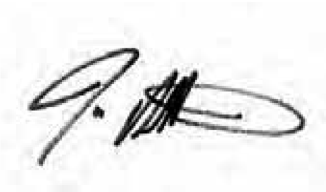
Our operational focus includes continuing to optimize plant capacity, availability and margin, through improvements in efficiency and reliability. Operations will continue to improve through a predictive and risk-based approach to maintenance.

Above all, 2013 will see our continuing, unwavering commitment to health, safety and environmental performance across our operations.

IN SUMMARY

It is with gratitude that we acknowledge the hard work and dedication of our employees. Across our businesses, the deep relationships cultivated by our 1,000+ employees with suppliers, customers, landowners, local communities, and regulators help to enhance our competitive position and fulfill our responsibility to all of our stakeholders. Our people are paramount to the success of our business and we are deeply grateful for their passion, integrity and commitment to our vision.

We would like to take this opportunity to thank the Board of Directors for its support and guidance over what has been a very busy and productive year. We also thank our shareholders for having confidence in our vision. We are working hard to continue to transform that vision into reality and appreciate your continued support as we advance our strategy in 2013.



Ian Robertson
CEO

Ken Moore
Chairman of the Board of Directors

Algonquin Power & Utilities Corp. is well positioned for continued long-term growth, while maintaining a low-to-moderate risk profile. Our Company has an experienced management team, dedicated employees, a strong balance sheet, an array of growth opportunities and a diverse portfolio of high quality assets across our utility businesses.

Management's Discussion and Analysis

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

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2012. The Management's Discussion and Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2012 and 2011. 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 March 14, 2013.

Caution concerning forward-looking statements and non-GAAP Measures

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require APUC to make assumptions and involve inherent risks and uncertainties. APUC cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; and the state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements. In addition, such statements are made based on information available and expectations as of the date of this MD&A and such expectations may change after this date. APUC reviews material forward-looking information it has presented, not less frequently than on a quarterly basis. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA"), "adjusted funds from operations", "per share cash provided by adjusted funds from operations" and "per share cash provided by operating activities" are used throughout this MD&A. The terms "adjusted net earnings", "per share cash provided by operating activities", "adjusted funds from operations", "per share cash provided by adjusted funds from operations" and Adjusted EBITDA are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations" and "per share cash provided by operating activities" consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations" and "per share cash provided by operating activities" can be found throughout this MD&A. Per share cash provided by operating activities is not a substitute measure of performance for earnings per share. Amounts represented by per share cash provided by operating activities do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

Overview and Business Strategy

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

APUC's current quarterly dividend to shareholders is $0.0775 per share or $0.31 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities and mitigate the impact of fluctuations in foreign exchange rates. Further increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board") with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

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

Algonquin Power Co.

APCo generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean energy power generation facilities located across North America. APCo seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

APCo owns or has interests in hydroelectric facilities with a combined generating capacity of approximately 170 MW. APCo also owns or has interests in wind powered generating stations with a combined generating capacity of 650 MW. Approximately 84% of the electrical output from the hydroelectric and wind generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 15 years.

APCo owns or has interests in thermal energy facilities with approximately 341 MW of installed generating capacity. Approximately 95% of the electrical output from the owned thermal facilities is sold pursuant to long term Power purchase agreements ("PPA") with major utilities and which have a weighted average remaining contract life of 7 years.

Liberty Utilities Co.

Liberty Utilities is a diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services. Liberty Utilities provides safe, high quality and reliable services to its ratepayers through its nationwide portfolio of utility systems and delivers stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities delivers continued growth in earnings through accretive acquisition of additional utility systems.

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

The Liberty Utilities (West) region is comprised of regulated electrical and water distribution and wastewater collection utility systems. The regulated electrical distribution utility and related generation assets (the "Calpeco Electric Utility") serve approximately 46,955 active electric connections in the State of California. Liberty Utilities (West) region's regulated water and wastewater utility systems serve approximately 66,550 water and wastewater connections located in the State of Arizona.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems. The regulated natural gas utilities serve approximately 82,050 active natural gas connections located in the States of Missouri, Illinois, and Iowa and the regulated water distribution and wastewater collection utilities serve approximately 11,500 water and wastewater customers located in the States of Arkansas, Illinois, Missouri, and Texas.

Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems located in the State of New Hampshire providing regulated local electrical utility services to approximately 43,250 active electric connections; and regulated local gas distribution utility services to approximately 87,650 active natural gas connections. Upon completion of certain pending acquisitions of natural gas utility systems located in Georgia and Massachusetts, the additional 114,000 customers will be added to the Liberty Utilities (East) region.

Major Highlights

Corporate Highlights

Dividend Increased to $0.31 per Common Share Annually

APUC has completed several acquisitions and has advanced a number of other initiatives that have raised the growth profile for APUC's earnings and cash flows which in turn supports an increase in the dividend to shareholders. As a result, on August 9, 2012, the Board approved a dividend increase of $0.03 per share annually bringing the total annual dividend to $0.31, paid quarterly at the rate of $0.0775 per common share.

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

Strengthened Balance Sheet

Issuance of $120M Preferred Shares

On November 9, 2012, APUC issued 4.8 million cumulative rate reset preferred shares, Series A (the "Series A Shares") at a price of $25 per share, for aggregate gross proceeds of $120 million. The shares will yield 4.5% annually for the initial six-year period ending on December 31, 2018. The preferred shares have been assigned a rating of P-3 and Pfd-3(low) by S&P and DBRS respectively. The proceeds of the offering were used primarily to partially fund the acquisition of the interest in the Gamesa wind powered generating stations (the "Gamesa Wind Facilities") which closed on December 10, 2012.

Emera Subscription Receipts

For the year ended December 31, 2012, APUC issued a total of 26.4 million shares for cash and share proceeds of $142.6 million pursuant to the exercise of subscription receipts issued to Emera in contemplation of certain previously announced transactions. The shares were issued in the context of the existing Strategic Investment Agreement which contemplates Emera's investment in APUC of up to 25%.

As at December 31, 2012, Emera owned 34.9 million APUC common shares representing approximately 18.5% of the total outstanding common shares of the Company.

Subsequent to the end of the year and pursuant to previously committed subscription receipts, APUC issued 2.6 million shares at a price of $5.74, 5.2 million shares at a price of $5.74 and 3.4 million shares at a price representing $4.72 per share pursuant to subscription agreements. As a result, at March 14, 2013, Emera owns 46.1 million APUC common shares representing approximately 23% of the total outstanding common shares of the Company.

On February 22, 2013, APUC announced that Emera agreed to subscribe to 4.0 million common shares of APUC at a price of $7.40 per share for total proceeds of approximately $29 million representing a $0.10 premium to the closing price of APUC shares on February 19, 2013. The conversion of these subscription receipts will bring Emera's total investment in APUC to 25%.

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

Conversion of Series 2A Convertible Debentures to Equity

On February 24, 2012 ("Series 2A Redemption Date"), APUC redeemed $57.0 million, representing the remaining issued and outstanding, Series 2A Debentures by issuing and delivering 9,836,520 APUC common shares. Between January 1, 2012 and the Series 2A Redemption Date, a principal amount of $2.9 million of Series 2A Debentures were converted into 485,998 common shares of APUC.

Conversion and Redemption of Series 3 Convertible Debentures to Equity

On December 31, 2012 ("Series 3 Redemption Date"), APUC converted $55.3 million of Series 3 Debentures by issuing and delivering 13,172,619 APUC common shares. On January 1, 2013, APUC completed a redemption of the outstanding Series 3 Debentures by issuing and delivering 150,816 APUC common shares for the remaining $0.9 million in Series 3 Debentures.

APUC Credit Facility

On November 19, 2012, APUC entered into an agreement for a $30.0 million senior unsecured revolving credit facility ("APUC Facility") with a Canadian chartered bank. The credit facility will be used for general corporate purposes and has a maturity date of November 19, 2015.

Liberty Utilities Highlights

Agreement to Acquire New England Utility

On February 11, 2013, Liberty Utilities entered into an agreement with The Laclede Group, Inc. ("Laclede") to assume Laclede's rights to purchase the assets of New England Gas Company ("NEGasCo Acquisition") from an affiliate of Southern Union Company. New England Gas Company is a natural gas distribution utility serving over 50,000 customers in Massachusetts. The acquisition is subject to certain approvals and conditions, including state and federal regulatory approval, and is expected to close in the second half of 2013.

Total consideration for the utility asset purchase is approximately U.S. $74 million, subject to working capital and closing adjustments representing a 1.0x premium to regulatory assets of $73.9 million. The purchase price will be funded using a target capital structure of 52% equity and 48% debt and will include the assumption of U.S. $19.5 million of existing debt.

Agreement to Acquire Georgia Utility

On August 8, 2012, Liberty Utilities entered into an agreement with Atmos to acquire certain regulated natural gas distribution utility systems (the "Georgia Utility") serving approximately 64,000 connections located in the State of Georgia. The total purchase price for the Georgia Utility is approximately U.S. $140.7 million representing a 1.1x premium to net assets for regulatory purposes of U.S. $128.1 million and is subject to certain working capital and other closing adjustments.

On February 22, 2013, Liberty Utilities has received all federal and state regulatory approvals required to complete the acquisition. Closing is expected to occur on or about April 1, 2013 and will be reported as part of the Liberty Utilities (East) region.

Acquisition of Remaining Interest in the California Utility

On December 21, 2012, APUC completed the acquisition of the remaining 49.999% ownership in California Pacific Utility Ventures LLC, which owns 100% of the Calpeco Electric Utility assets. APUC acquired the remaining 49.999% interest from Emera through proceeds received from the issuance of 8.2 million APUC common shares, 4.8 million of which were issued on December 27, 2012, and the remaining 3.4 million shares issued on February 14, 2013.

Acquisition of New Hampshire Utility

On July 3, 2012, Liberty Utilities completed the acquisition of all issued and outstanding shares of Granite State Electric Co. ("Granite State Electric Utility") and EnergyNorth Natural Gas Inc. ("EnergyNorth Gas Utility"), both from National Grid, for consideration of U.S. $285.0 million plus working capital and other closing adjustments for a total consideration of U.S. $295.8 million. The purchase price for the utility assets represents a multiple of aggregate expected regulatory assets of approximately 1.14x. The regulated electric distribution company provides electric service to over 43,000 connections in 21 communities in New Hampshire and the regulated natural gas distribution utility provides natural gas service to over 87,000 connections in five counties and 30 communities in New Hampshire.

In the first half of 2013, Granite State Electric Utility will file a rate case with the New Hampshire Public Utilities Commission ("NHPUC") seeking an increase in distribution base rates. The filing is based on a 2012 test year, with revenues and expenses reflecting known and measurable changes. The regulatory process associated with the rate case is expected to last one year, with temporary rates expected to be implemented on or about July 1, 2013 and the final permanent rates determined in the rate case going into effect on or about March 2014.

Acquisition of Missouri Utility

On August 1, 2012, Liberty Utilities completed the acquisition of regulated natural gas distribution utility systems (the "Midwest Gas Utilities") located in Missouri, Illinois, and Iowa from Atmos Energy Corporation ("Atmos") for consideration of U.S. $127.7 million plus working capital and other closing adjustments for a total consideration of U.S. $128.2 million.

The acquisition was originally announced in May 2011 and final regulatory approvals were received in June 2012. The purchase price for the utility assets represented a multiple of net assets for regulatory purposes of approximately 1.1x. Collectively, the regulated natural gas distribution systems provide natural gas service to approximately 82,000 connections.

Acquisition of Arkansas Utility

On February 1, 2013, Liberty Utilities completed the acquisition of issued and outstanding shares of United Water Arkansas Inc., a regulated water distribution utility ("Pine Bluff Water Utility") from United Waterworks Inc. The Pine Bluff Water Utility is located in Pine Bluff, Arkansas and serves approximately 17,000 customers. Total purchase price for the Pine Bluff Water Utility was approximately U.S. $27.6 million representing a 1.16x premium to net utility assets of U.S. $24.6 million and subject to certain working capital and other closing adjustments. The Pine Bluff Water Utility will be included in the Liberty Utilities (Central) region.

U.S. Debt Private Placements

In connection with the above noted gas and electric utility acquisitions during the third quarter, Liberty Utilities completed a U.S. $225 million private placement debt financing. The financing was closed in two tranches contemporaneously with the closing of the New Hampshire and Missouri Utilities acquisitions. The notes are senior unsecured notes with an average life maturity of over ten years and a weighted average coupon of 4.38%. The notes have been assigned a rating of "BBB high" by DBRS Limited. Proceeds from the private placement were used to partially fund the New Hampshire and Midwest Gas Utilities acquisitions.

Subsequent to the year end on March 14, 2013 Liberty Utilities completed a U.S. $15 million private placement debt financing in connection with the above noted acquisition of an Arkansas water utility. The notes are senior unsecured with a 10 year term and a coupon of 4.14%.

U.S. $100 million Acquisition Term Facility

On March 14, 2013 Liberty Utilities entered into a U.S. $100 million term loan with a U.S. Bank. The loan facility is available for acquisitions and general corporate purposes and matures on December 31, 2013.

Expansion of Liberty Utilities Credit Facility

In 2012, Liberty Utilities entered into an agreement for a U.S. $100 million senior unsecured revolving credit facility (the "Liberty Facility") with a consortium of U.S. banks. The Liberty Facility will be used for general corporate purposes and has a three year term with a maturity date of January 18, 2015.

Algonquin Power Co. Highlights

Acquisition of U.S. Wind Facilities

In 2012 APCo completed its 60% equity investment in a portfolio of three wind powered generating stations: Minonk Wind (200MW), Senate Wind (150MW) and Sandy Ridge Wind (50MW) Facilities ("Gamesa Wind Facilities") located in the states of Illinois, Texas, and Pennsylvania, respectively for consideration of $271.7 million.

The Gamesa Wind Facilities were acquired through a newly formed partnership whose members include Class B members consisting of APCo (60% interest in Class B membership units) and Gamesa Energy USA, LLC ("Gamesa USA"), a subsidiary of Gamesa Corporación Tecnológica, S.A., the original developer of the projects, (holding a 40% interest in Class B membership units) and certain Class A equity investors who are primarily entitled to the tax attributes associated with the projects. Total cost of the three wind farms was approximately $747 million.

The Gamesa Wind Facilities utilize Gamesa G9X-2.0 MW wind turbines. Gamesa USA has assumed all operations, maintenance, and capital repair responsibilities for the facilities pursuant to a 20 year agreement for the turbines and balance of plant facilities.

Total annual energy production is expected to be 1,352 GW-hrs per year. The Gamesa Wind Facilities have long term, fixed price power sales contracts (the "Power Sales Contracts") with a weighted average life of 11.8 years (Minonk and Sandy Ridge Wind Facilities 10 years each, Senate Wind Facility 15 years). Approximately 73% of energy revenues would be earned under the Power Sales Contracts. All energy produced in excess of that sold under the Power Sales Contracts, together with ancillary services including capacity and renewable energy credits, will be sold into the energy markets in which the facilities are located.

Acquisition of Shady Oaks Wind Facility

Effective January 1, 2013, APCo acquired a 109.5 MW contracted wind powered generating station ("Shady Oaks Wind Facility") from Goldwind International SO Limited ("Goldwind") for total consideration of approximately US$148.9 million.

The Shady Oaks Wind Facility is located in Northern Illinois, approximately 80 km west of Chicago, Illinois and reached commercial operation in June 2012.

The facility is comprised of 68 Goldwind GW82 1.5MW and 3 Goldwind GW100 2.5MW permanent magnet direct-drive wind turbines; these turbines are well suited for the wind regime, and offer significant technological advantages providing proven reliability, enhanced energy production efficiency and lower long term maintenance costs. Through its affiliate, Goldwind has assumed all operations, maintenance, and capital repair responsibilities for the Shady Oaks Wind Facility pursuant to a 20 year fixed price agreement for the turbines and balance of plant facilities.

Total annual energy production is expected to be 364 GW-hrs per year. The Shady Oaks Wind Facility has entered into a 20 year inflation indexed power purchase agreement with the largest electric utility in the state of Illinois, Commonwealth Edison (BBB flat stable: Moody's, S&P) for 310 GW-hrs of energy per year. All energy produced in excess of that sold under the power purchase agreement will be sold into the energy market in which the facility is located.

APCo $150 million Senior Unsecured Debentures

On December 3, 2012, APCo issued $150 million 4.82% senior unsecured debentures with a maturity date of February 15, 2021 (the "APCo Debentures") pursuant to a private placement in Canada and the United States. The APCo Debentures were sold at a price of $99.94 per $100.00 principal amount, resulting in an effective yield to maturity of 4.83% per annum. Concurrent with the offering, APCo entered into a fixed for fixed cross currency swap, coterminous with the APCo Debentures, to economically convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of 4.4%.

Net proceeds from the APCo Debentures were used primarily to fund the 400MW investment in the Gamesa Wind Facilities discussed above.

APCo Credit Facility

On November 16, 2012, APCo amended its existing $155 million senior secured credit facility ("APCo Facility") to increase the commitments available under the Facility to $200 million. In addition, the bank syndicate has agreed to release its security previously held over certain APCo entities, such that the amended APCo Facility is now fully unsecured. The APCo Facility now has a maturity date of November 16, 2015.

Completion of Windsor Locks Repowering

APCo has completed the repowering of the Windsor Locks electrical and steam energy generating station. The installation of a new 14 MW Solar Titan combustion gas turbine was completed in July

2012 at a total capital cost of U.S. $18.3 million (net of one-time non-recurring items: State of Connecticut grant for U.S. $6.5 million; and a U.S. Federal Government heat and power investment tax credit ("ITC") for U.S. $2.4 million) and is now fully operational. As part of the repowering project APCo also entered into an extension of the energy services agreement with Ahlstrom for delivery of 100% of its steam capacity and a portion of its electrical generating capacity. The agreement now continues until 2027. With the new turbine operational the existing Frame 6 is now available as a peaking turbine to generate additional revenues.

Sale of Small U.S. Hydro Facilities

On March 14, 2013, APCo entered into an agreement to sell 10 small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of the Company for gross proceeds of U.S. $27 million. The operating results from these facilities are therefore disclosed as discontinued operations on the consolidated statements of operations and prior periods have been reclassified to conform to this presentation.

2012 Annual Results from Operations

During the year, APUC positioned both its regulated and non-regulated utility businesses for significant growth in 2013 and beyond. Growth expected in the first quarter of 2013 will reflect the acquisition of 3 U.S. wind generation facilities near the end of the year. The acquisition of natural gas and electric utilities in the third quarter of 2012 will also contribute to significant growth expected in 2013 as cash flow and earnings from these utilities are heavily weighted to the first and second quarters of each year.

Key Selected Annual Financial Information

	Year ended December 31		
(millions of dollars except per share information)	2012	2011	2010
Revenue	**$ 369.9**	$ 270.7	$ 175.1
Adjusted EBITDA [1, 3]	**106.2**	103.7	74.1
Cash provided by operating activities	**63.0**	69.7	41.4
Adjusted funds from operations[1, 3]	**76.9**	72.7	41.5
Net earnings attributable to Shareholders from continuing operations	**15.7**	24.1	18.3
Net earnings attributable to Shareholders	**14.5**	23.4	18.0
Adjusted net earnings [1, 3]	**21.1**	38.3	22.8
Dividends declared to Common Shareholders	**50.2**	32.4	22.8
Weighted Average number of common shares outstanding	**158,304,340**	116,712,934	94,338,193
Per share			
Basic net earnings from continuing operations	**$ 0.10**	$ 0.21	$ 0.19
Basic net earnings	**$ 0.09**	$ 0.20	$ 0.19
Adjusted net earnings [1, 2, 3]	**$ 0.14**	$ 0.33	$ 0.24
Diluted net earnings	**$ 0.09**	$ 0.20	$ 0.19
Cash provided by operating activities [1, 2, ,3]	**$ 0.40**	$ 0.60	$ 0.44
Adjusted funds from operations[1, 2, 3]	**$ 0.52**	$ 0.62	$ 0.44
Dividends declared to Common Shareholders	**$ 0.30**	$ 0.27	$ 0.24
Total assets	**2,778.2**	1,282.3	1,016.9
Long term liabilities[4]	**771.8**	455.0	441.7

[1] APUC uses adjusted EBITDA, adjusted net earnings and adjusted funds from operations to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.
[2] APUC uses per share adjusted net earnings, cash provided by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.
[3] Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.
[4] Long term debt includes current and long term portion of debt and convertible debentures.

For the year ended December 31, 2012, APUC experienced an average U.S. exchange rate of approximately $0.999 as compared to $0.989 in the same period in 2011. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's Canadian dollar reporting currency.

For the year ended December 31, 2012, APUC reported total revenue of $369.9 million as compared to $270.7 million during the same period in 2011, an increase of $99.2 million or 37%. The major factors resulting in the increase in APUC revenue for the year ended December 31, 2012 as compared to the corresponding period in 2011 are set out as follows:

		Year ended December 31, 2012
		(Millions)
Comparative Prior Period Revenue	$	270.7
Significant Changes:		
Liberty Utilities:		
West – Lower electricity sales to customers		(5.4)
Central – Revenue increase due to Midwest Gas Utilities acquisitions		26.2
East – Gas and electricity revenue due to EnergyNorth Gas Utility and Granite State Electric Utility acquisitions		86.9
APCo:		
Renewable:		
Effect of hydrology resource compared to comparable period in prior year		(4.7)
Acquisition of Sandy Ridge, Minonk, and Senate Wind Facilities		3.9
St Leon Wind Facility– Effect of wind resource compared to comparable period in prior year		(1.0)
St Leon II Wind Facility – Revenue increase from expansion		1.6
Tinker Hydro/AES – Increased demand for retail sales		2.8
Thermal:		
Windsor Locks and Sanger Thermal Facilities – Lower power demand and rates, and offline for major maintenance		(10.7)
Energy-from-Waste Facility – Lower price per tonne for supplemental waste		(2.1)
Impact of the stronger U.S. dollar		1.1
Other		0.6
Current Period Revenue	$	369.9

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

Adjusted EBITDA in the year ended December 31, 2012 totalled $106.2 million as compared to $103.7 million during the same period in 2011, an increase of $2.5 million or 2%. The increase in Adjusted EBITDA was primarily due to revenues from the St. Leon facility expansion and the EnergyNorth Gas Utility, Granite State Electric Utility, Midwest Gas Utilities, and the Gamesa Wind Facilities acquisitions which closed near the end of the year. These items were partially offset by lower results from operations primarily from lower hydrology in APCo's Renewable Energy Division, reduced energy sales at APCo's Windsor Locks facility during the re-powering, reduced margins at APCO's energy sales group, increased administrative expenses and lower customer demand at the Liberty Utilities (West)'s electric distribution utility. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the year ended December 31, 2012, net earnings attributable to Shareholders totalled $14.5 million as compared to $23.4 million during the same period in 2011, a decrease of $8.9 million. Net earnings per share totalled $0.09 for the year ended December 31, 2012, as compared to $0.20 during the same period in 2011.

The decrease in net earnings attributable to Shareholders for the year ended December 31, 2012 was due to $10.1 million increased depreciation and amortization expense, $2.1 million related to increased administration charges, $0.1 million due to a stronger U.S. dollar, $5.5 million in higher interest expense, $4.7 million in increased acquisition costs, $9.0 million in reduced recoveries of income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)*, $0.4 million due to a greater loss from discontinued operations, and $3.5 million in increased allocations of earnings to non-controlling interests as compared to the same period in 2011. These items were partially offset by $3.7 million increased earnings from operating facilities, $15.2 million in decreased write-downs of long lived assets, $1.6 million in increased interest, dividend and other income, and $6.0 million in increased gains from derivative instruments as compared to the same period in 2011.

During the year ended December 31, 2012, cash provided by operating activities totalled $63.0 million or $0.40 per share as compared to cash provided by operating activities of $69.7 million, or $0.60 per share during the same period in 2011. During the year ended December 31, 2012, adjusted funds from operations, a non-GAAP measure, totalled $76.9 million or $0.52 per share as compared to adjusted funds from operations of $72.7 million, or $0.62 per share during the same period in 2011. The change in adjusted funds from operations in the year ended December 31, 2012, is primarily due to reduced earnings from operations, partially offset by increased interest, dividend and other income as compared to the same period in 2011.

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

2012 Three month results from operations

Key Selected Fourth Quarter Financial Information

(millions of dollars except per share information)	Quarter ended December 31 2012		2011	
Revenue	**$**	**143.1**	$	70.5
Adjusted EBITDA [1, 3]		**33.4**		24.3
Cash provided by operating activities		**16.1**		1.4
Adjusted funds from operations[1, 3]		**26.9**		12.7
Net earnings / (loss) attributable to Shareholders from continuing operations		**6.6**		(7.7)
Net earnings / (loss) attributable to Shareholders		**6.4**		(8.5)
Adjusted net earnings[1, 3]		**5.4**		3.6
Dividends declared to Common Shareholders		**15.5**		9.5
Weighted Average number of common shares outstanding		**172,474,338**		130,805,502
Per share				
Basic net earnings/(loss) from continuing operations	**$**	**0.04**	$	(0.06)
Basic net earnings/(loss)	**$**	**0.04**		(0.07)
Adjusted net earnings[1, 2, 3]	**$**	**0.03**	$	0.03
Diluted net earnings/(loss)	**$**	**0.04**	$	(0.07)
Cash provided by operating activities [1, 2, ,3]	**$**	**0.09**	$	0.01
Adjusted funds from operations[1, 2, 3]	**$**	**0.16**	$	0.10
Dividends declared to Common Shareholders	**$**	**0.08**	$	0.07

[1] APUC uses adjusted EBITDA, adjusted net earnings and adjusted funds from operations to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.
[2] APUC uses per share adjusted net earnings, cash provided by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.
[3] Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

For the three months ended December 31, 2012, APUC experienced an average U.S. exchange rate of approximately $0.991 as compared to $1.023 in the same period in 2011. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the three months ended December 31, 2012, APUC reported total revenue of $143.1 million as compared to $70.5 million during the same period in 2011, an increase of $72.6 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2012 as compared to the corresponding period in 2011 are set out as follows:

	Quarter ended December 31, 2012 (Millions)	
Comparative Prior Period Revenue	**$**	70.5
Significant Changes:		
Liberty Utilities:		
West – Lower electricity sales to customers		(1.3)
Central – Revenue increase due to Midwest Gas Utilities acquisitions		20.7
East – Gas and electricity revenue due to EnergyNorth Gas Utility and Granite State Electric Utility acquisitions		55.6
APCo:		
Renewable		
Effect of hydrology resource compared to comparable period in prior year		(1.2)
Acquisition of Sandy Ridge, Minonk, and Senate Wind Facilities		3.2
St Leon Wind Facility – effect of lower wind resource compared to comparable period in prior year		(1.6)
St Leon II Wind Facility– Revenue increase from expansion		0.9
Thermal		
Windsor Locks Thermal Facility – Lower power demand and rates		(0.8)
Energy-from-Waste Facility – Lower price per tonne for supplemental waste		(1.5)
Impact of the weaker U.S. dollar		(2.1)
Other		0.7
Current Period Revenue	**$**	143.1

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

Adjusted EBITDA in the three months ended December 31, 2012 totalled $33.4 million as compared to $24.3 million during the same period in 2011, an increase of $9.1 million or 37%.

The increase in Adjusted EBITDA was primarily due to increased revenues from EnergyNorth Gas Utility, Granite State Electric Utility, Midwest Gas Utilities, and the U.S. Wind Project acquisitions, and increased demand at the Liberty Utilities (West)'s electric distribution utility. These items were partially offset by lower results from operations primarily from increased energy costs for APCO's energy sales group, lower revenues from APCo's EFW facility due to the expiry of the Region of Peel contract, and reduced wind resources at APCo's St Leon facility. 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 December 31, 2012, net income attributable to Shareholders totalled $6.4 million as compared to net loss attributable to Shareholders of $8.5 million during the same period in 2011, an increase of $14.9 million. Net income per share totalled $0.04 for the three months ended December 31, 2012, as compared to net loss per share of $0.07 during the same period in 2011.

The increase in net earnings attributable to Shareholders for the quarter ended December 31, 2012 was due to $10.0 million increased earnings from operating facilities, $15.2 million in decreased write-downs of long lived assets, $2.0 million due to a stronger U.S. dollar, $1.1 million in increased interest, dividend and other income, $2.0 million in increased gains from derivative instruments, $0.7 million in reduced losses from discontinued operations and $0.5 million in increased recoveries of income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2011. These items were partially offset by $6.5 million increased depreciation and amortization expense, $0.5 million related to increased administration charges, $3.7 million in higher interest expense, $0.1 million in increased acquisition costs, and $5.8 million in increased allocations of earnings to non-controlling interests as compared to the same period in 2011.

During the three months ended December 31, 2012, cash provided by operating activities totalled $16.1 million or $0.09 per share as compared to cash provided by operating activities of $1.4 million, or $0.01 per share during the same period in 2011. During the three months ended December 31, 2012, adjusted funds from operations totalled $26.9 million or $0.16 per share as compared to adjusted funds from operations of $12.7 million, or $0.10 per share during the same period in 2011. The change in adjusted funds from operations in the three months ended December 31, 2012, is primarily due to decreased earnings from operations, partially offset by increased interest, dividend and other income as compared to the same period in 2011.

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

Outlook

Overall APUC expects operational results for power generation in the first quarter of 2013 to reflect long-term average resource conditions for hydroelectric and wind power generation.

APUC expects continuing modest customer growth throughout its regulated utilities service territories in 2013 and that utility operations will meet APUC's expectations for the first quarter of 2013.

As a result of several acquisitions concluded by APUC over the past 9 months, the Company's results in the first quarter of 2013 is expected to show growth compared to the first quarter of 2012. APUC's results will reflect several acquisitions which have now closed but were not part of APUC's operations in the first quarter of 2012. These acquisitions include the Shady Oaks Wind Facility and the Gamesa Wind Facilities, the Pine Bluff Water Utility, the Midwest Gas Utilities, EnergyNorth Gas Utility and Granite State Electric Utility.

APCo: Renewable Energy Division

	Long Term Average Resource	Three months ended December 31 2012	Three months ended December 31 2011	Long Term Average Resource	Year ended December 31 2012	Year ended December 31 2011
Performance (GW-hrs sold)						
Hydro Facilities:						
Quebec Region	**73.8**	**70.0**	79.3	**279.7**	**263.4**	304.4
Ontario Region	**31.9**	**6.9**	28.8	**133.7**	**95.6**	121.1
Western Region	**12.6**	**11.5**	11.8	**65.0**	**64.4**	65.5
Maritime Region	**33.6**	**24.1**	40.2	**125.8**	**112.9**	183.0
	151.9	**112.5**	160.1	**604.2**	**536.3**	674.0
Wind Facilities:						
Manitoba Region	**121.4**	**106.6**	119.7	**424.0**	**405.0**	383.8
Saskatchewan Region[1]	**23.7**	**20.7**	27.7	**88.4**	**82.8**	68.0
Pennsylvania Region[2]	**43.6**	**34.8**	-	**72.5**	**55.9**	-
Illinois Region[3]	**47.1**	**46.8**	-	**47.1**	**46.8**	-
Texas Region[3]	**33.8**	**34.0**	-	**33.8**	**34.0**	-
	269.6	**242.9**	147.4	**665.8**	**624.5**	451.8
Total	**421.5**	**355.4**	307.5	**1,270.0**	**1,160.8**	1,125.8
Revenue[4]		**(millions)**	(millions)		**(millions)**	(millions)
Energy sales		**$ 21.5**	$ 22.3		**$ 84.2**	$ 81.6
Less:						
Cost of Sales – Energy[5]		(1.7)	(0.7)		**(8.9)**	(3.8)
Net Energy Sales		**$ 19.8**	$ 21.6		**$ 75.3**	$ 77.8
Other Revenue		**0.8**	0.3		**1.9**	2.3
Total Net Revenue		**$ 20.6**	$ 21.9		**$ 77.2**	$ 80.1
Expenses						
Operating expenses		(5.4)	(6.7)		**(21.4)**	(21.6)
Interest and Other income		**0.5**	0.6		**2.0**	2.1
Division operating profit		**$ 15.7**	$ 15.8		**$ 57.8**	$ 60.6

1 APUC does not consolidate the operating results from this facility in its financial statements. Production from the facility is included as APUC manages the facility under contract and has an option to acquire a 75% equity interest in the facility in 2016. The prior year actual production in the Saskatchewan Region reflects production since Red Lily I achieved commercial operation on February 23, 2011. The long term average resource reflects three and twelve months of production.

2 Represents the operations of Sandy Ridge Wind Facility which was acquired on July 1, 2012.

3 Represents the operations of Minonk and Senate Wind Facilities in the states of Illinois and Texas, respectively which was acquired on December 10, 2012.

4 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.

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

2012 Annual Operating Results

Production data, revenue and expenses have been adjusted to remove the results of the New York and New England regional assets which are now disclosed as discontinued operations. See Financial Statement note 18 for details.

For the year ended December 31, 2012, the Renewable Energy Division produced 1,160.8 GW-hrs of electricity, as compared to 1,125.8 GW-hrs produced in the same period in 2011, an increase of 3%. The increased generation is primarily due to additional wind production in Canada from the expansion of St. Leon and the addition of the Gamesa Wind Facilities, partially offset by reduced hydrology and wind resource in 2012 as compared to the comparable period in 2011. The level of production in 2012 represents sufficient renewable energy to supply the equivalent of 64,500 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 640,000 tons of CO_2 gas was prevented from entering the atmosphere in the year ended December 31, 2012.

During the year ended December 31, 2012, the Renewable Energy Division generated electricity equal to 91% of long-term projected average resources (wind and hydrology) as compared to 107% during the same period in 2011. For the year ended December 31, 2012, the new Texas region experienced resources higher than long-term averages resources, whereas the Quebec, Western, Maritimes, Manitoba, Saskatchewan regions and the new Illinois region experienced below long-term averages resources, with energy production consistent with resources between 1%-10% below long-term average resources. The Ontario and Pennsylvania regions experienced results between 23%-29% below long-term average resources. The Ontario region's lower production was primarily due to an unplanned shutdown at the Long Sault facility.

For the year ended December 31, 2012, revenue from energy sales in the Renewable Energy Division totalled $84.2 million, as compared to $81.6 million during the same period in 2011. 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 year ended December 31, 2012, net revenue from energy sales in the Renewable Energy Division totalled $75.3 million, as compared $77.8 million during the same period in 2011.

Revenue generated from APCo's hydro facilities located in the Quebec and Western regions decreased by $3.6 million primarily due to $5.1 million in lower hydrology and partially offset by $1.5 million due to an increase in weighted average energy rates, as compared to the same period in 2011. Revenue from lost production due to the unplanned shutdown in Ontario was covered by business interruption insurance claim proceeds in the amount of $1.8 million. Revenue from APCo's hydro facility located in the Maritime region decreased by 10% primarily driven by a $1.8 million in decreased customer demand offset by a $1.5 million increase in weighted average energy rates as compared to the same period in 2011.

Revenue from APCo's wind facilities located in the Manitoba region increased $0.7 million primarily due to the expansion of the St. Leon facility offset by a lower than average wind resource. APCo's wind facilities located in the new Pennsylvania, Texas, and Illinois regions, which were acquired in late 2012, produced revenue of $3.9 million.

Revenue at the Energy Services Business increased 24% due to $6.4 million of increased customer demand, partially offset by a $3.2 million decrease in weighted average energy rates. Revenue at the Energy Services Business primarily consists of wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine, and merchant sales of production in excess of customer demand at the Tinker hydroelectric generating facility.

For the year ended December 31, 2012, energy purchase costs by the Energy Services Business totalled $8.9 million as compared to $3.8 million during the same period in 2011, an increase of $5.1 million. During this period, the Energy Services Business purchased approximately 140.7 GW-hrs of energy at market and fixed rates averaging U.S. $63 per MW-hr. The Maritime region generated approximately 43% of the load required to service its customers as well as the customers of the Energy Services Business in the year ended December 31, 2012, as compared to 80% in the same period in 2011. The lower production from the Maritime region was the primary driver for the increased energy purchase costs for the year ended December 31, 2012. The division reported increased energy purchase costs of $0.1 million as a result of the stronger U.S. dollar as compared to the same period in 2011.

The Red Lily I wind farm located in Saskatchewan produced 82.8 GW-hrs of electricity for the year ended December 31, 2012. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges and is not reflected in revenues from energy sales. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily I for a direct 75% equity interest in 2016. For the year ended December 31, 2012, APCo earned fees and interest payments from Red Lily I in the total amount of $3.2 million.

The Renewable Energy Division reported increased revenue of $0.2 million from U.S. operations as a result of the stronger U.S. dollar as compared to the same period in 2011.

For the year ended December 31, 2012, operating expenses excluding energy purchases totalled $21.4 million, as compared to $21.6 million during the same period in 2011, a decrease of $0.2 million or 1%. The decrease was primarily impacted by $1.8 million in lower operating costs at the hydro facilities due to lower flows and related direct production costs, and $0.3M in lower personnel costs at the Energy Services Business. These items were partially offset by a $0.5 million accrual for costs related to the Quebec water lease proceedings and by $1.4 million in operating costs related to the U.S. Wind Project acquisitions and other business development initiatives such as the Cornwall Solar development.

For the year ended December 31, 2012, interest and other income totalled $2.0 million, consistent with the same period in 2011. Interest and other income primarily consists of interest related to the senior and subordinated debt interest in the Red Lily I wind project. This amount is included as part of APCo's earnings from its investment in Red Lily I, as discussed above.

For the year ended December 31, 2012, the Renewable Energy Division's operating profit totalled $57.8 million, as compared to $60.6 million during the same period of 2011, representing a decrease of $2.8 million or 5%.

2012 Fourth Quarter Operating Results

For the quarter ended December 31, 2012, the Renewable Energy Division produced 355.4 GW-hrs of electricity, as compared to 307.5 GW-hrs produced in the same period in 2011, an increase of 16%. The increased generation is primarily due to the acquisition of Sandy Ridge, Minonk and Senate Wind Facilities. This level of production represents sufficient renewable energy to supply the equivalent of 79,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 195,500 tons of CO2 gas was prevented from entering the atmosphere in the fourth quarter of 2012.

During the quarter ended December 31, 2012, the division generated electricity equal to 84% of long-term projected average resources (wind and hydrology) as compared to 109% during the same period in 2011. In the fourth quarter of 2012, the new Texas region experienced resources slightly higher than long-term averages resources, whereas the new Illinois region as well as the Western, and Quebec regions experienced resources slightly lower than long-term averages resources, producing 1-9% below long-term average resources. The Manitoba, Saskatchewan and Pennsylvania regions produced 12-20% below long-term averages resources. The Ontario and Maritimes regions produced well below long-term averages resources, primarily due to the unplanned outage at the Long Sault Facility.

For the quarter ended December 31, 2012, revenue from energy sales in the Renewable Energy Division totalled $21.5 million, as compared to $22.3 million during the same period in 2011. 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 December 31, 2012, net revenue from energy sales in the Renewable Energy Division totalled $19.8 million, as compared $21.6 million during the same period in 2011.

Revenue generated from APCo's hydro facilities located in the Ontario, Quebec and Western regions decreased by $1.1 million due to a $1.3 million overall decrease in hydrology, primarily in the Ontario and Quebec regions, offset partially by a $0.2 million increase in weighted average energy rates as compared to the same period in 2011. Lost production from the unplanned shutdown in Ontario was covered by business interruption insurance claim proceeds in the amount of $1.8 million. Revenue from APCo's hydro facility located in the Maritime region decreased primarily due to a $0.5 million decrease in customer demand, partially offset by a $0.2 million increase in weighted average energy rates as compared to the same period in 2011.

Revenue from APCo's wind facilities located in the Manitoba region decreased $0.7 million primarily due to lower than normal wind resource, decreased weighted average energy rates realized on production in excess of contracted dependable volumes partially offset by an increase in production from the expansion of the facility. Revenue from APCo's wind facilities located in the new Pennsylvania, Texas, and Illinois regions which accounts for Sandy Ridge, Minonk and Senate Wind Facilities, the three U.S. Wind Project interests acquired in 2012, produced revenue of $3.2 million.

Revenue at AES increased 5% primarily due to $0.5 million of increased customer demand, partially offset by a $0.4 million decrease in weighted average energy rates. Revenue at AES primarily consists of wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine, merchant sales of production in excess of customer demand at the Tinker Facility and other revenue.

For the quarter ended December 31, 2012, energy purchase costs by AES totalled $1.7 million as compared to $0.7 million during the same period in 2011, an increase of $1.0 million. During this period, AES purchased approximately 22.1 GW-hrs of energy at market and fixed rates averaging U.S. $76 per MW-hr. During the quarter, the Maritime region generated approximately 52% of the load required to service its customers as well as AES' customers, as compared to 70% in the same period in 2011. The lower production from the Maritime region was a result of a planned shutdown to implement various equipment upgrades. This planned shutdown and resultant lower production was the primary driver for AES' increased energy purchase costs for the quarter ended December 31, 2012. The division reported decreased energy purchase costs of $0.1 million as a result of the weaker U.S. dollar as compared to the same period in 2011.

The division reported decreased revenue of $0.2 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2011.

The Red Lily I wind farm located in Saskatchewan produced 20.7 GW-hrs of electricity for the quarter ended December 31, 2012. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges and is not reflected in revenues from energy sales. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily for a direct 75% equity interest in 2016. For the quarter ended December 31, 2012, APCo earned fees and interest payments from Red Lily in the total amount of $0.9 million.

For the quarter ended December 31, 2012, operating expenses excluding energy purchases totalled $5.4 million, as compared to $6.7 million during the same period in 2011, a decrease of $1.3 million or 19%. The decrease was primarily impacted by a $1.0 million decrease in costs in the Ontario region as a result of the unplanned shut down of the Long Sault facility, as compared to the same period in 2011.

For the quarter ended December 31, 2012, interest and other income totalled $0.5 million, consistent with the same period in 2011. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in the Red Lily I project. This amount is included as part of APCo's earnings from its investment in Red Lily I, as discussed above.

For the quarter ended December 31, 2012, the Renewable Energy Division's operating profit totalled $15.7 million, as compared to $15.8 million during the same period in 2011, representing a decrease of $0.1 million or 1%.

APCo: Thermal Energy Division

	Three months ended December 31 2012	Three months ended December 31 2011	Year ended December 31 2012	Year ended December 31 2011
Performance (GW-hrs sold)	80.5	126.5	330.5	517.0
Performance ('000 tonnes of waste processed)	36.6	42.1	163.8	166.8
Performance (steam sales – billion lbs)	342.2	308.4	1,305.6	1,209.4
	(millions)	(millions)	**(millions)**	(millions)
Revenue				
Energy/steam sales	**$** 11.3	$ 10.6	**$** 36.9	$ 46.7
Less:				
Cost of Sales – Fuel [1]	(4.4)	(7.8)	(14.6)	(24.6)
Net Energy/Steam Sales Revenue	**$** 6.9	$ 2.8	**$** 22.3	$ 22.1
Waste disposal sales	2.7	4.0	14.3	16.4
Other revenue	0.6	0.5	1.7	1.4
Total net revenue	**$** 10.2	$ 7.3	**$** 38.3	$ 39.9
Expenses				
Operating expenses [1]	(5.2)	(3.3)	(21.1)	(19.9)
Interest and other income	(0.3)	(0.1)	0.5	-
Division operating profit	**$** 5.3	$ 3.9	**$ 17.7**	$ 20.0

[1] Cost of Sales – Fuel consists of natural gas and fuel costs at the Sanger and Windsor Locks facilities.

APCo's Sanger and Windsor Locks generation facilities purchase natural gas from different suppliers and at prices based on different regional hubs. As a result, the average landed cost per unit of natural gas will differ between facility and regional changes in the average landed cost for natural gas may result in one facility showing increasing costs per unit while the other shows decreasing costs, as compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each MMBTU.

2012 Annual Operating Results

For the year ended December 31, 2012, the Thermal Energy Division produced 330.5 GW-hrs of energy as compared to 517.0 GW-hrs of energy in the comparable period of 2011, primarily due to the planned outages at the Sanger and Windsor Locks facilities. During the year ended December 31, 2012, the business unit's total production decreased by 157.0 GW-hrs at the Windsor Locks facility and by 31.8 GW-hrs from the Sanger facility, as compared to the same period in 2011.

For the year ended December 31, 2012, the Energy-from-Waste ("EFW") facility processed approximately 163,800 tonnes of municipal solid waste as compared to 166,800 tonnes of municipal solid waste in the same period of 2011. The current level of production resulted in the diversion of approximately 127,200 tonnes of waste from municipal solid waste landfill sites in the twelve months of 2012.

For the year ended December 31, 2012, the Brampton Cogeneration Inc. ("BCI") and Windsor Locks facilities sold 1,305.6 billion lbs of steam as compared to 1,209.4 billion lbs of steam in the comparable period of 2011. During the year ended December 31, 2012, operations at the EFW facility generated 489 billion lbs of steam for the BCI facility as compared to 507 billion lbs of steam in the same period in 2011.

For the year ended December 31, 2012, energy / steam revenue in the Thermal Energy Division totalled $36.9 million, as compared to $46.7 million during the same period in 2011, a decrease of $9.8 million, or 21%. The decreased revenue from energy / steam sales as compared to the same period in 2011, was primarily due to a decrease in revenue of $7.9 million from lower production at the Windsor Locks facility as a result of a planned shutdown in the second quarter of 2012 to install the new Solar Titan combustion gas turbine, and a decrease of $1.9 million in lower production at the Sanger facility as a result of being offline for a planned shutdown commencing in January 2012.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as an appropriate measure of the division's results. For the year ended December 31, 2012, net energy / steam sales revenue at the Thermal Energy Division totalled $22.3 million, as compared to $22.1 million during the same period in 2011, an increase of $0.2 million. The increase is primarily due to lower gas costs as a result of increased operating efficiency and appropriate scale of the new Titan turbine installed at the Windsor Locks facility in 2012, partially offset by the Sanger facility being offline from January to April 2012 and the Windsor Locks facility being offline for a large part of the second quarter of 2012, and a $1.8 million reclassification from operating expenses into cost of sales – fuel in 2011 related to the KMS and Peel facilities.

For the year ended December 31, 2012, fuel costs at Sanger and Windsor Locks totalled $14.6 million, as compared with $24.6 million in the same period in 2011, a decrease of $10.0 million. The overall natural gas expense at the Windsor Locks facility decreased $6.6 million or 36%, primarily due to a 37% decrease in volume of natural gas consumed, partially offset by a 1% increase in the average landed cost of natural gas per MMBTU as compared to the same period in 2011. The average landed cost of natural gas at the Windsor Locks facility during the year ended December 31, 2012 was $4.91 per MMBTU. Natural gas expense at Sanger decreased $1.9 million or 39%, primarily the result of a 22% decrease in the volume of natural gas consumed in addition to a 22% decrease in the average landed cost of natural gas per MMBTU as compared to the same period in 2011. The average landed cost of natural gas at the Sanger facility during the year ended December 31, 2012 was U.S. $3.45 per MMBTU. A portion of the decrease in gas costs is attributable to a $1.8 million reclassification from operating expenses into cost of sales – fuel in 2011 related to the KMS and Peel facilities. The division reported increased fuel costs of $0.3 million as a result of the stronger U.S. dollar as compared to the same period in 2011.

Revenue from waste disposal sales for the year ended December 31, 2012 totalled $14.3 million, as compared to $16.4 million during the same period in 2011, a decline of $2.1 million or 13%. Revenue declined as the result of a greater level of supplemental waste processed by the facility for which lower average rates are charged pursuant to the existing waste disposal contract and the contract with the region of Peel expiring in October of 2012.

For the year ended December 31, 2012, operating expenses, excluding fuel costs at EFW, Windsor Locks and Sanger, totalled $21.1 million, as compared to $19.9 million during the same period in 2011, an increase of $1.2 million. The increase in operating expenses was primarily impacted by a $1.8 million reclassification from operating expenses into cost of sales – fuel in 2011 related to the KMS and Peel facilities offset by lower expenses of $0.3 million at the EFW facility, primarily related to lower gas and maintenance costs, and lower expenses of $0.2 million due to planned shutdowns of the Sanger and Windsor Locks facilities for portions of the twelve months of 2012.

For the year ended December 31, 2012, the Thermal Energy Division's operating profit totalled $17.7 million, as compared to $20.0 million during the same period in 2011, representing a decrease of $2.3 million or 12%.

2012 Fourth Quarter Operating Results

For the quarter ended December 31, 2012, the Thermal Energy Division produced 80.5 GW-hrs of energy as compared to 126.5 GW-hrs of energy in the comparable period of 2011. The decrease in energy production was due primarily to the installation of the new Titan turbine which is a smaller, more efficient turbine, sized to optimize the energy and steam requirements of the steam host compared to the larger, less efficient Frame 6 turbine that was operating the previous year.

The EFW facility processed approximately 36,600 tonnes of municipal solid waste in the quarter as compared to 42,100 tonnes of municipal solid waste in the same period of 2011. The current level of production resulted in the diversion of approximately 32,600 tonnes of waste from municipal solid waste landfill sites in the fourth quarter of 2012.

For the quarter ended December 31, 2012, the BCI and Windsor Locks facilities sold 342.2 billion lbs of steam as compared to 308.4 billion lbs of steam in the comparable period of 2011. During the quarter ended December 31, 2012, operations at the EFW facility generated 103.5 billion lbs of steam for the BCI facility as compared to 129.0 billion lbs of steam in the same period in 2011.

For the quarter ended December 31, 2012, energy / steam revenue in the Thermal Energy Division totalled $11.3 million, as compared to $10.6 million during the same period in 2011, an increase of $0.7 million, or 7%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as an appropriate measure of the division's results. For the quarter ended December 31, 2012, net energy / steam sales revenue at the Thermal Energy Division totalled $6.9 million, as compared to $2.8 million during the same period in 2011, an increase of $4.1 million. The increase is primarily attributed to lower fuel costs at Windsor Locks as a result of the installation of the new Titan Turbine and a $1.8 million reclassification from operating expenses into cost of sales – fuel in 2011 related to the KMS and Peel facilities.

Revenue from energy / steam sales increased by $0.7 million as a result of $2.4 million in higher rates at the Windsor Locks facility as compared to the same period in 2011 and increased production volumes of 3% at the Sanger facility, offset by a decrease of $3.2 million in production at Windsor Locks and a 1% decrease in billing rates at Sanger.

For the quarter ended December 31, 2012, fuel costs at Sanger and Windsor Locks totalled $4.4 million, as compared with $6.0 million (net of the $1.8 million reclassification) in the same period in 2011, a decrease of $1.6 million. The overall natural gas expense at the Windsor Locks facility decreased $1.1 million or 25%, primarily the result of a 43% decrease in volume of natural gas consumed, offset by a 32% increase in the average landed cost of natural gas per MMBTU as compared to the same period in 2011. The average landed cost of natural gas at the Windsor Locks facility during the quarter was $6.29 per MMBTU. Natural gas expense at Sanger increased 3%, primarily the result of a 0.2% decrease in the average landed cost of natural gas per MMBTU offset by a 3% increase in the volume of natural gas consumed as compared to the same period in 2011. The average landed cost of natural gas at the Sanger facility during the quarter was U.S. $4.02 per MMBTU. The division reported decreased fuel costs of $0.2 million as a result of the weaker U.S. dollar as compared to the same period in 2011.

Revenue from waste disposal sales at the EFW facility for the quarter ended December 31, 2012 totalled $2.7 million as compared to $4.0 million during the same period in 2011, primarily due to the expiration of the Region of Peel contract.

For the quarter ended December 31, 2012, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $5.2 million as compared to $3.3 million during the same period in 2011, an increase of $1.9 million, primarily as a result of a $1.8 million reclassification from operating expenses into cost of sales – fuel in 2011 related to the KMS and Peel facilities.

For the quarter ended December 31, 2012, the Thermal Energy Division's operating profit totalled $5.3 million, as compared to $3.9 million during the same period in 2011.

APCo: Development Division

The Development Division works to identify, develop and construct new power generating facilities, as well as to identify, and acquire, operating projects that would be complementary and accretive to APCo's existing portfolio. The Development Division is focused on projects within North America and is committed to working proactively with all stakeholders including local communities. APCo's approach to project development and acquisition is to maximize the utilization of internal resources while minimizing external costs. This allows projects to mature to the point where most major elements and uncertainties 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 or execute an acquisition agreement.

Projects Currently in Development

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

Project Name	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GW-hrs
Chaplin Wind [1]	Saskatchewan	177	$355.0	2016	25	720.0
Amherst Island [2]	Ontario	75	$230.0	2015	20	247.0
Val Eo [1]	Quebec	24	$70.0	2015	20	66.0
Morse Wind [3, 4]	Saskatchewan	25	$70.0	2014	20	93.0
St. Damase [1]	Quebec	24	$66.0	2014	20	78.7
Cornwall Solar [1, 2]	Ontario	10	$45.0	2013	20	13.4
Total		**335**	**$836.0**			**1,218.1**

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

Chaplin Wind

In the first quarter of 2012, APCo entered into a 25 year PPA with SaskPower for development of a 177 MW wind power project in the rural municipality of Chaplin, Saskatchewan, 200 km west of Regina, Saskatchewan.

The project has a targeted commercial operation date of December, 2016. The facility will be constructed at an estimated capital cost of $355 million and consist of approximately 77 multi-megawatt wind turbines. The project is expected to generate first full year EBITDA of $37.5 million. The 25 year PPA features a rate escalation provision of 0.6% throughout the term of the agreement. The project will take advantage of its favourable location by interconnecting with a nearby 138Kv line and will be compliant with SaskPower's latest interconnection requirements.

Amherst Island Wind

The Amherst Island wind project is located on Amherst Island in the village of Stella, approximately 25 kilometres southwest of Kingston, Ontario. In February 2011, the 75 MW project was awarded a feed-in tariff ("FIT") contract by the OPA as part of the second round of the OPA's FIT program.

The FIT contract originally stated that the OPA had the option to terminate the FIT contract prior to the date that the OPA had issued a Notice to Proceed ("NTP") and APCo had paid the incremental security required by the NTP. On August 2, 2011, the Ontario Ministry of Energy directed the OPA to offer FIT contract holders the opportunity to have the OPA's termination rights under the FIT contract waived. APCo exercised this option on August 9, 2011. As required by the waiver, APCo submitted a domestic content plan on October 14, 2011 and provided a statutory declaration regarding equipment supply commitments by November 30, 2011.

The Amherst Island wind project is currently contemplated to use efficient Class III wind turbine generator technology. APCo forecasts that the available wind resource could produce approximately 247 GW-hrs of electrical energy annually, depending upon the final turbine selection for the project. Total capital costs for the facility are currently estimated to be $230 million. The financing of the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. Environmental studies and engineering are underway. The final open-house for public consultation was conducted on March 5th and 6th, 2013. The submission of the Renewable Energy Approval application subsequent to the open house is targeted for April 2013. Construction will commence shortly following the approval of the application and is expected to take 12 to 18 months.

Morse Wind Project

The Morse wind project is comprised of three contiguous projects with 25 MW of aggregate installed generating capacity. The project is to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina. It is contemplated that the project will have additional land under lease or option in order to facilitate future expansion.

APCo executed an asset purchase agreement with a local developer ("Kineticor") to acquire assets related to two adjacent 10 MW wind energy development projects in Saskatchewan and a further 5 MW was developed by APCo independently. All of the individual projects comprising the Morse wind project were selected by SaskPower in accordance with the SaskPower Green Options Partners Program. The two 10 MW projects were awarded in May 2010 and the 5 MW project was awarded in June 2011. The execution of the PPA pursuant to this program is expected to take place concurrently with the execution of the Interconnection Agreement in late March of 2013. The Environmental Impact Assessment was submitted for the project in mid-2012 and as a result the project was deemed "not a development". This allows the project to proceed towards the construction phase without the requirement for a full Environmental Assessment. The expected date of operation for the projects is in early 2015.

The total annual energy production for the Morse wind project is estimated to be 93,000 MW-hrs. The capital cost to construct the Morse wind project is currently estimated to be between $65 million and $70 million, inclusive of acquisition costs. The first year PPA rate is set at $101.98 per MW-hr for the first full year of operations, which APCo expects to occur in 2014, with an annual escalation provision of 2% over the expected 20 year term.

Quebec Community Wind Projects

In December 2010, APCo in partnership with Société en Commandite Val-Éo, a community cooperative with a development project located in the Lac Saint-Jean region of Quebec, and in partnership with the community of Saint-Damase were awarded PPAs for the construction of two wind power projects in the Province of Quebec using ENERCON wind turbines. Both projects will represent phase one in the potential development of a larger second phase.

1. *Saint-Damase*

Phase one of the Saint-Damase wind project is located in the local municipality of Saint-Damase which is within the regional municipality of la Matapédia. The project proponents include the Municipality of Saint-Damase and APCo. At the request of the turbine manufacturer, the project has recently gone through a turbine model change, changing from the originally proposed 8 wind turbines (E-101) of 3 MW each to 10 wind turbines (E-92) of 2.35 MW each. The annual energy production is estimated at 78,700 MW-hrs with a total installed capacity of 23.5 MW for the first phase. The second phase of the project would entail the development of an additional 106 MW's. The permitting and the environmental impact assessment are ongoing and the construction of the first project phase is to begin in the fall of 2013. Commercial operations are expected to commence in late 2014.

APCo's interest in the project will not be less than 50%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and community consultations were conducted in July 2011, March 2012 and September 2012. The project's social acceptance is strong and there will be no requirement for a public hearing under the auspices of the BAPE. The environmental impact assessment for the project has also been submitted and is under review with provincial ministerial approval anticipated for the third quarter of 2013.

2. *Val-Éo*

Phase one of the Val-Éo wind project is located in the local municipality of Saint-Gideon de Grandson, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APCo. The first 24 MW phase of the project is expected to be comprised of eight wind turbines, producing approximately 66,000 MW-hr annually. Construction of the first 24 MW phase of the project is expected to begin in the fall of 2014 with commercial operations commencing in late 2015. The second phase of the project would entail the development of an additional 106 MW's.

APCo's interest in the project is subject to final negotiations with the Val-Éo community cooperative but, in any event, will not be less 25%. Final funding of the project will be arranged and announced when all required permitting has been secured, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and studies of flora and fauna and the public consultation process are ongoing. The submission of the environmental impact study to the Minister of Sustainable Development, Environment, Wildlife and Parks is targeted for the second quarter of 2013.

Cornwall Solar

In the first quarter of 2012, APCo acquired all of the issued and outstanding shares of Cornwall Solar Inc. ("Cornwall Solar"), which owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario (the "Cornwall Project"). In addition to the Cornwall Project, APCo has acquired an option to acquire ten additional Ontario based solar projects. APCo has submitted FIT applications for an additional 100MWac.

The Cornwall Project has been granted an Ontario FIT contract by the OPA, with a 20 year term and a rate of $443/MW-hr, resulting in expected initial annual revenues of approximately $6.2 million. The Cornwall Project contemplates the use of a ground-mounted PV array system, installed on two parcels of leased land totalling approximately 138 acres.

The project received its Renewable Energy Approval on January 15th, 2013, and construction of the project is expected to begin in the second quarter of 2013. The project's environmental assessment has now been deemed "administratively complete". Commercial operation is estimated in late 2013 with expected annual generation of approximately 13,400 MW-hrs.

Total capital cost of the project is targeted at approximately $45 million, including the consideration to be paid for the acquisition of the project. Funding for the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied.

APCo Outlook

The APCo Renewable Energy Division is expected to perform based on long-term average resource conditions for both wind and hydrology in the first quarter of 2013. In October 2012, APCo's hydroelectric generating facility at Long Sault experienced an unplanned shut down. The facility is expected to return to full service in the second quarter of 2013. New York and New England facilities are expected to perform at similar levels as the previous year. The acquisitions of an interest in the Sandy Ridge Wind Facility (on July 1, 2012), the Minonk and Senate Wind Facilities (on December 10, 2012), and the Shady Oaks Wind Facility (on January 1, 2013) are recently acquired wind powered generating stations that will generate additional revenue in 2013.

Unlike 2012, there are no planned outages in 2013 for the Thermal Energy Division. After installation of the new Solar Titan combustion gas turbine in the third quarter of 2012, the Windsor Locks facility is better able to match production with demand from its industrial host under a PPA, limiting its exposure to the more volatile market power pricing in New England. In October 2012, the EFW facility received approval from the Ontario Ministry of Environment for an amendment to its environmental permits allowing the EFW facility to accept municipal, industrial, commercial and institutional waste from anywhere in Ontario. APCo has now entered into several waste supply agreements to ensure continued operation of the facility following the end of the Region of Peel waste supply contract in 2012.

Liberty Utilities™

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

Utility System Type	December 31, 2012			December 31, 2011		
	Assets		Connections	Assets		Connections
		U.S. $ (millions)			U.S. $ (millions)	
Electricity	$	254.3	90,205	$	155.8	46,906
Natural Gas		394.8	169,700		-	-
Water and Wastewater		205.4	78,050		203.4	76,100
	$	854.5	337,955	$	359.2	123,006

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

The Liberty Utilities (West) region is currently comprised of regulated electrical and water distribution and wastewater collection utility systems. The regulated electrical distribution utility serves approximately 46,955 active electric connections in the State of California. The Liberty Utilities (West) region's regulated water and wastewater utility systems serve approximately 66,550 water and wastewater connections located in the State of Arizona. These utilities systems, previously reported in the Liberty Utilities (South) region, have now been combined with Liberty Utilities (West) for reporting purposes, effective July 1, 2012.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems. The regulated natural gas utilities serve approximately 82,050 active natural gas connections located in the states of Missouri, Illinois, and Iowa and the regulated water distribution and wastewater collection utilities serve approximately 11,500 water and wastewater customers located in the states of Illinois, Missouri, and Texas.

Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems located in the State of New Hampshire which provides regulated local electrical utility services to approximately 43,250 active electric connections; and regulated local gas distribution utility services to approximately 87,650 active natural gas connections.

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

Liberty Utilities: West Region

	Year ended December 31	
	2012	**2011**
Number of Active Electric Connections		
Residential	41,400	41,346
Commercial – Small	5,500	5,506
Commercial – Large	55	54
Total Active Electric Connections	**46,955**	**46,906**
Number of Water Connections		
Wastewater connections	31,750	30,900
Water distribution connections	34,800	33,900
Total Water Connections	**66,550**	**64,800**
Customer Usage (GW-hrs)		
Residential	273.6	291.2
Commercial – Small	149.7	173.1
Commercial – Large	121.0	136.6
Public Street and Highway Lighting	1.1	1.1
Total Customer Usage (GW-hrs)	**545.4**	**602.0**
Gallons Provided		
Wastewater treated (millions of gallons)	1,650	1,710
Water sold (millions of gallons)	5,080	5,190
Total Gallons Provided	**6,730**	**6,900**

Liberty Utilities (West) is comprised of Liberty Utilities operations in California and Arizona. On December 21, 2012, Liberty Utilities (West) acquired the remaining 49.999% interest in the Calpeco Electric Utility. Therefore, as at December 31, 2012, Liberty Utilities (West) holds a 100% interest in the Calpeco Electric Utility.

Liberty Utilities (West)'s increase in water and wastewater connections during the period is primarily due to development within the service territory.

For the year ended December 31, 2012, Liberty Utilities (West)'s electricity usage totalled 545.4 GW-hrs, as compared to 602.0 GW-hrs for the same period in 2011, a decrease of 56.6 GW-hrs or 9%. This decrease in usage was primarily due to milder winter and spring weather in 2012 as compared to the colder weather experienced in the same period a year ago. Under the rate tariff approved in November 2012, and commencing on January 1, 2013, the revenues earned by the Calpeco Electric Utility will not reflect variations due to customer demand variability.

During the year ended December 31, 2012, Liberty Utilities (West) provided approximately 5.1 billion U.S. gallons of water to its customers, treated approximately 1.7 billion U.S. gallons of wastewater and sold approximately 360 million U.S. gallons of treated effluent.

	Year ended December 31				Year ended December 31			
		2012		2011		2012		2011
		U.S. $ (millions)		U.S. $ (millions)		**Can $ (millions)**		Can $ (millions)
Water Assets for regulatory purposes		**181.3**		180.3				
Electricity Assets for regulatory purposes		**165.9**		155.8				
Revenue								
Utility electricity sales and distribution[1]	**$**	**72.0**	$	78.1	**$**	**71.7**	$	77.4
Wastewater treatment		**18.7**		18.2		**18.7**		18.0
Water distribution		**18.6**		18.3		**18.6**		18.1
Other Revenue		**0.2**		-		**0.2**		-
Total Revenue	**$**	**109.5**	$	114.6	**$**	**109.2**	$	113.5
Less:								
Cost of Sales – Electricity [1]		**(44.0)**		(46.9)		**(43.9)**		(46.5)
	$	**65.5**	$	67.7	**$**	**65.3**	$	67.0
Expenses								
Operating expenses		**(35.7)**		(34.8)		**(35.6)**		(34.5)
Other income		**2.1**		0.5		**2.1**		0.5
Divisional operating profit	**$**	**31.9**	$	33.4	**$**	**31.8**	$	33.0

1 Represents 100% of investment in the Calpeco Electric Utility

2012 Annual Operating Results

Liberty Utilities (West) has investments in water and wastewater distribution assets for regulatory purposes of U.S. $181.3 million in the state of Arizona and electricity assets for regulatory purposes of U.S. $165.9 million in the State of California as at December 31, 2012, as compared to U.S. $180.3 million and U.S. $155.8 million, respectively as at December 31, 2011.

For the year ended December 31, 2012, Liberty Utilities (West)'s revenue totalled U.S. $109.2 million as compared to U.S. $113.5 million during the same period in 2011, a decrease of U.S. $4.3 million or 4%.

For the year ended December 31, 2012, Liberty Utilities (West)'s revenue from utility electricity sales totalled U.S. $72.0 million as compared to U.S. $78.1 million during the same period in 2011, a decrease of U.S. $6.1 million or 8%. This decrease in revenues was primarily due to milder winter and spring weather in the first half of 2012, compared with the colder winter weather experienced in the same period a year ago. The decreased utility electricity sales were primarily a result of a U.S. $6.3 million decrease due to a decrease in customer demand and partially offset by an increase of U.S. $0.2 million due to increased weighted average electricity and general rates as compared to the same period in 2011. The purchase of electricity by Liberty Utilities (West) is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, Liberty Utilities (West) compares 'net utility electricity sales' (utility electricity sales less fuel and purchased power costs) as a more appropriate measure of the division's results. For the year ended December 31, 2012, net utility electricity sales revenues for Liberty Utilities (West) were U.S. $28.0 million, as compared to U.S. $31.2 million during the same period in 2011. Under the rate tariffs approved in November 2012, and commencing on January 1, 2013, the revenues earned by the Calpeco Electric Utility will not experience fluctuations related to variations in customer demand.

For the year ended December 31, 2012, revenue from wastewater treatment totalled U.S. $18.7 million, as compared to U.S. $18.2 million during the same period in 2011, an increase of U.S. $0.5 million or 3%.

Revenue from water distribution totalled U.S. $18.6 million, as compared to U.S. $18.3 million during the same period in 2011, an increase of U.S. $0.3 million or 2%. The twelve months of water distribution revenue was impacted by U.S. $0.1 million at the Litchfield Park ("LPSCo") facility primarily due to the increased residential, commercial and industrial revenue and U.S. $0.2 million at the Sierra Vista facilities due to increase in connection counts and overall consumption, U.S. $0.1 million at all other Liberty Utilities (West) water utilities, offset by a $0.1 million decrease at the LPSCo facility primarily due to the decreased residential usage revenue.

For the year ended December 31, 2012, fuel and purchased power costs for Liberty Utilities (West)'s electric utility totalled U.S $44.0 million, as compared with U.S. $46.9 million for the same period in 2011. The overall electricity purchase expense decrease of U.S. $2.9 million was primarily the result of a $3.8 million decrease in the volume of electricity purchased to meet customer demand, partially offset by a U.S. $0.9 million increase in weighted average electricity rates as compared to the same period in 2011.

For the year ended December 31, 2012, operating expenses totalled U.S. $35.7 million, as compared to U.S. $34.8 million during the same period in 2011. The increase in operating expenses was due to increases in customer care expenses, increases in general and administrative expenses, and increases in bad debt expense relating to uncollectible customer accounts receivable as compared to the same period in 2011.

For the year ended December 31, 2012, Liberty Utilities (West)'s operating profit was U.S. $31.9 million as compared to U.S. $33.4 million in the same period in 2011, a decrease of U.S. $1.5 million or 4%.

Measured in Canadian dollars, for the year ended December 31, 2012, Liberty Utilities (West)'s revenue from utility electricity sales totalled $71.7 million, as compared to $77.4 million during the same period in 2011. For the year ended December 31, 2012, net utility electricity sales for Liberty Utilities (West) totalled $27.8 million, as compared to $30.9 million during the same period in 2011.

Measured in Canadian dollars, for the year ended December 31, 2012, electricity purchases for Liberty Utilities (West) totalled $43.9 million, as compared to $46.5 million in the same period in 2011.

Measured in Canadian dollars, for the year ended December 31, 2012, Liberty Utilities (West)'s revenue from water treatment and wastewater distribution totalled $37.3 million, as compared to $36.1 million during the same period in 2011.

Measured in Canadian dollars, for the year ended December 31, 2012, operating expenses totalled $35.6 million, as compared to $34.5 million during the same period in 2011.

Measured in Canadian dollars, for the year ended December 31, 2012, Liberty Utilities (West)'s operating profit totalled $31.8 million as compared to $33.0 million during the same period in 2011.

	Three months ended December 31	
	2012	**2011**
Customer Usage (GW-hrs)		
Residential	72.2	69.4
Commercial – Small	42.3	50.2
Commercial – Large	39.2	40.4
Public Street and Highway Lighting	0.3	0.2
Total Customer Usage (GW-hrs)	**154.0**	**160.2**
Gallons Provided		
Wastewater treated (millions of gallons)	425	410
Water sold (millions of gallons)	1,255	1,225
Total Gallons Provided	**1,680**	**1,635**

For the three months ended December 31, 2012, Liberty Utilities (West) electricity usage totalled 154.0 GW-hrs, as compared to 160.2 GW-hrs for the same period in 2011, a decrease of 6.2 GW-hrs or 4%.

During the quarter ended December 31, 2012, Liberty Utilities (West) provided approximately 1.25 billion U.S. gallons of water to its customers, treated approximately 425 million U.S. gallons of wastewater and sold approximately 113 million U.S. gallons of treated effluent.

		Three months ended December 31				Three months ended December 31		
		2012		2011		2012		2011
		U.S. $ (millions)		U.S. $ (millions)		**Can $ (millions)**		Can $ (millions)
Revenue								
Utility electricity sales and distribution*	**$**	**19.5**	$	20.8	$	**19.3**	$	21.3
Wastewater treatment		**4.7**		4.5		**4.7**		4.6
Water distribution		**4.4**		4.4		**4.4**		4.5
Other Revenue		**-**		-		**-**		-
	$	**28.6**	$	29.7	$	**28.4**	$	30.4
Less:								
Cost of Sales – Electricity		**(11.5)**		(13.2)		**(11.4)**		(13.5)
	$	**17.1**	$	16.5	**$**	**17.0**	$	16.9
Expenses								
Operating expenses		**(9.3)**		(9.9)		**(9.4)**		(10.1)
Other income		**1.1**		0.2		**1.1**		0.2
Division operating profit*	**$**	**8.9**	$	6.8	**$**	**8.7**	$	7.0

2012 Fourth Quarter Operating Results

For the three months ended December 31, 2012, Liberty Utilities (West)'s revenue totalled U.S. $28.6 million as compared to U.S. $29.7 million during the same period in 2011, a decrease of U.S. $1.1 million.

For the three months ended December 31, 2012, Liberty Utilities (West)'s revenue from utility electricity sales totalled U.S. $19.5 million as compared to U.S. $20.8 million during the same period in 2011, a decrease of U.S. $1.3 million or 6%. Revenue decreased U.S. $0.9 million due to decreased customer demand and decreased U.S. $0.4 million due to decreased weighted average electricity and general rates as compared to the same period in 2011. The purchase of electricity by Liberty Utilities (West) is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, Liberty Utilities (West) compares 'net utility electricity sales' (utility electricity sales revenue less electricity purchases) as a more appropriate measure of the division's results. For the three months ended December 31, 2012, net utility electricity sales for Liberty Utilities (West) totalled U.S. $8.0 million, as compared to U.S. $7.6 million during the same period in 2011, an increase of U.S. $0.4 million or 5%.

For the three months ended December 31, 2012, revenue from wastewater treatment and water distribution totalled U.S. $9.1 million, as compared to U.S. $8.9 million during the same period in 2011, an increase of U.S. $0.2 million or 2%.

For the three months ended December 31, 2012, fuel and purchased power costs for Liberty Utilities (West) totalled U.S $11.5 million, as compared with U.S. $13.2 million in the same period in 2011. The decrease of U.S. $1.7 million was a result of a 4% decrease in the volume of electricity used and a 9% decrease in average cost of electricity as compared to the same period in 2011.

For the three months ended December 31, 2012, operating expenses totalled U.S. $9.3 million, as compared to U.S. $9.9 million during the same period in 2011, a decrease of U.S. $0.6 million or 6%. Operating expenses decreased due to reduced utilities and consumable expenses as compared to the same period in 2011.

For the three months ended December 31, 2012, Liberty Utilities (West)'s operating profit was U.S. $8.9 million as compared to U.S. $6.8 million in the same period in 2011, an increase of U.S. $2.1 million or 31%.

Measured in Canadian dollars, for the three months ended December 31, 2012, Liberty Utilities (West)'s revenue from utility electricity sales totalled $19.3 million, as compared to $21.3 million during the same period in 2011. For the three months ended December 31, 2012, net utility electricity sales for Liberty Utilities (West) totalled $7.9 million, as compared to $7.8 million during the same period in 2011.

Measured in Canadian dollars, for the three months ended December 31, 2012, electricity purchases for Liberty Utilities (West) totalled $11.4 million, as compared to $13.5 million in the same period in 2011.

Measured in Canadian dollars, for the three months ended December 31, 2012, Liberty Utilities (West)'s revenue from water treatment and wastewater distribution totalled $9.1 million, which was consistent with the same period in 2011.

Measured in Canadian dollars, for the three months ended December 31, 2012, operating expenses totalled $9.4 million, as compared to $10.1 million in the same period in 2011.

Measured in Canadian dollars, for the three months ended December 31, 2012, Liberty Utilities (West)'s operating profit totalled $8.7 million as compared to $7.0 million in the same period in 2011.

Liberty Utilities: Central Region

	Year ended December 31 2012	2011
Number of Active Natural Gas Connections		
Residential	72,500	-
Commercial	9,500	-
Industrial	50	-
Total Active Natural Gas Connections	**82,050**	**-**
Number of Water Connections		
Wastewater connections	6,000	5,900
Water distribution connections	5,500	5,400
Total Water Connections	**11,500**	**11,300**
Customer Usage (MMBTU)		
Residential	1,306,800	-
Commercial	914,150	-
Industrial	178,900	-
Total Customer Usage (MMBTU)[1]	**2,399,850**	**-**
Gallons Provided		
Wastewater treated (millions of gallons)	370	290
Water sold (millions of gallons)	385	410
Total Gallons Provided	**755**	**700**

[1] Represents MMBTU since August 1, 2012 acquisition date

Liberty Utilities (Central) is comprised of Liberty Utilities' operations in Texas, Missouri, Illinois, and Iowa. Liberty Utilities (Central) acquired its natural gas distribution utilities on August 1, 2012 and accordingly there are no results for these utilities for the corresponding period in 2011.

From the acquisition date of August 1, 2012 to December 31, 2012, Liberty Utilities (Central) natural gas distribution sales totalled 2,399,850 MMBTU.

During the year ended December 31, 2012, Liberty Utilities (Central) provided approximately 385 million U.S. gallons of water to its customers, and treated approximately 370 million U.S. gallons of wastewater.

	Year ended December 31 2012	2011	Year ended December 31 2012	2011
	U.S. $ (millions)	U.S. $ (millions)	**Can $ (millions)**	Can $ (millions)
Natural Gas Assets for regulatory purposes	**131.4**	-		
Water Assets for regulatory purposes	**24.1**	23.1		
Revenue				
Utility natural gas sales and distribution [1]	**$ 26.0**	$ -	**$ 25.8**	$ -
Wastewater treatment	**5.7**	5.7	**5.7**	5.6
Water distribution	**3.4**	3.3	**3.4**	3.2
	35.1	9.0	**34.9**	8.8
Less:				
Cost of Sales – Natural Gas[1]	**(13.8)**	-	**(13.6)**	-
	$ 21.3	$ 9.0	**$ 21.3**	$ 8.8
Expenses				
Operating expenses	**(13.1)**	(4.3)	**(13.1)**	(4.3)
Divisional operating profit	**$ 8.2**	$ 4.7	**$ 8.2**	$ 4.5

[1] Represents Natural Gas revenue and gas costs since August 1, 2012 acquisition date.

2012 Annual Operating Results

Liberty Utilities (Central) has investments in natural gas distribution assets for regulatory purposes of U.S. $131.4 million and water distribution assets for regulatory purposes of U.S. $24.1 million as at December 31, 2012, as compared to U.S. $nil and U.S. $23.1 million, respectively as at December 31, 2011.

For the year ended December 31, 2012, Liberty Utilities (Central)'s revenue totalled U.S. $35.1 million as compared to U.S. $9.0 million during the same period in 2011, an increase of U.S. $26.1 million. The revenue increase can be primarily attributed to the addition of the natural gas distribution assets on August 1, 2012.

From the date of acquisition to December 31, 2012, Liberty Utilities (Central)'s revenue from natural gas sales and distribution totalled U.S. $26.0 million. The purchase of natural gas by Liberty Utilities (Central) is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the division compares 'net utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. From the date of acquisition to December 31, 2012, net utility natural gas sales and distribution revenue for Liberty Utilities (West) totalled U.S. $12.2 million.

From the date of acquisition to December 31, 2012, natural gas purchases for Liberty Utilities (Central) totalled U.S $13.8 million.

For the year ended December 31, 2012, revenue from wastewater treatment and water distribution totalled U.S. $9.1 million, as compared to U.S. $9.0 million during the same period in 2011, an increase of U.S. $0.1 million or 1%.

For the year ended December 31, 2012, operating expenses, excluding natural gas purchases, totalled U.S. $13.1 million, as compared to U.S. $4.3 million during the same period in 2011. The increase in operating expenses can be mostly attributed to the addition of the natural gas distribution assets on August 1, 2012.

For the year ended December 31, 2012, Liberty Utilities (Central)'s operating profit was U.S. $8.2 million as compared to U.S. $4.7 million in the same period in 2011, an increase of U.S. $3.5 million or 74%.

Measured in Canadian dollars, from the date of acquisition to December 31, 2012, Liberty Utilities (Central)'s revenue from natural gas sales and distribution totalled $25.8 million. From the date of acquisition to December 31, 2012, net utility natural gas sales and distribution revenue for Liberty Utilities (Central) totalled $12.2 million.

Measured in Canadian dollars, from the date of acquisition to December 31, 2012, natural gas purchases for Liberty Utilities (Central) totalled $13.6 million.

Measured in Canadian dollars, for the year ended December 31, 2012, Liberty Utilities (Central)'s revenue from water treatment and wastewater distribution totalled $9.1 million, as compared to $8.8 million during the same period in 2011. Liberty Utilities (Central) reported a foreign exchange impact on revenue from water treatment and wastewater distribution of $0.2 million in the twelve months ended December 31, 2012 as a result of the stronger U.S. dollar as compared to the same period in 2011.

Measured in Canadian dollars, for the year ended December 31, 2012, operating expenses, excluding natural gas purchases totalled $13.1 million, as compared to $4.3 million during the same period in 2011.

Measured in Canadian dollars, for the year ended December 31, 2012, Liberty Utilities (Central)'s operating profit totalled $8.2 million as compared to $4.5 million in the same period in 2011.

	Three months ended December 31	
	2012	**2011**
Customer Usage (MMBTU)		
Residential	1,160,000	-
Commercial	709,750	-
Industrial	131,300	-
Total Customer Usage (MMBTU)	**2,001,050**	**-**
Gallons Provided		
Wastewater treated (millions of gallons)	95	90
Water sold (millions of gallons)	100	75
Total Gallons Provided	**195**	**165**

For the three months ended December 31, 2012, Liberty Utilities (Central) natural gas distribution sales totalled 2,001,050 MMBTU.

During the three months ended December 31, 2012, Liberty Utilities (Central) provided approximately 100 million U.S. gallons of water to its customers, and treated approximately 95 million U.S. gallons of wastewater.

		Three months ended December 31				Three months ended December 31		
		2012		2011		2012		2011
		U.S. $ (millions)		U.S. $ (millions)		**Can $ (millions)**		Can $ (millions)
Revenue								
Utility natural gas sales and distribution	**$**	**20.5**	$	-	**$**	**20.4**	$	-
Wastewater treatment		**1.5**		1.5		**1.4**		1.5
Water distribution		**0.7**		0.8		**0.7**		0.9
		22.7		2.3		**22.5**		2.4
Less:								
Cost of Sales – Natural Gas		**(12.0)**		-		**(11.9)**		-
	$	**10.7**	$	2.3	**$**	**10.6**	$	2.4
Expenses								
Operating expenses		**(6.3)**		(1.2)		**(6.3)**		(1.2)
Division operating profit	**$**	**4.4**	**$**	1.1	**$**	**4.3**	**$**	1.2

2012 Fourth Quarter Operating Results

For the three months ended December 31, 2012, Liberty Utilities (Central)'s revenue totalled U.S. $22.7 million as compared to U.S. $2.3 million during the same period in 2011, an increase of U.S. $20.4 million. The revenue increase can be primarily attributed to the addition of the natural gas distribution assets on August 1, 2012.

For the three months ended December 31, 2012, Liberty Utilities (Central)'s revenue from natural gas sales and distribution totalled U.S. $20.5 million. The purchase of natural gas by Liberty Utilities (Central) is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the division compares 'net utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. For the three months ended December 31, 2012, net utility natural gas sales and distribution revenue for Liberty Utilities (Central) totalled U.S. $8.5 million.

For the three months ended December 31, 2012, natural gas purchases for Liberty Utilities (Central) totalled U.S $12.0 million.

For the three months ended December 31, 2012, revenue from wastewater treatment and water distribution totalled U.S. $2.2 million, as compared to U.S. $2.3 million during the same period in 2011, a decrease of U.S. $0.1 million or 4%.

For the three months ended December 31, 2012, operating expenses, excluding natural gas purchases, totalled U.S. $6.3 million, as compared to U.S. $1.2 million during the same period in 2011. The increase in operating expenses can be mostly attributed to the addition of the natural gas distribution assets on August 1, 2012.

For the three months ended December 31, 2012, Liberty Utilities (Central)'s operating profit was U.S. $4.4 million as compared to U.S. $1.1 million in the same period in 2011, an increase of U.S. $3.3 million, primarily related to the acquisition of the natural gas utility.

Measured in Canadian dollars, for the three months ended December 31, 2012, Liberty Utilities (Central)'s revenue from utility natural gas sales and distribution totalled $20.4 million. Measured in Canadian dollars, for the three months ended December 31, 2012, net utility natural gas sales and distribution revenue for Liberty Utilities (Central) totalled $8.5 million.

Measured in Canadian dollars, for the three months ended December 31, 2012, natural gas purchases for Liberty Utilities (Central) totalled $11.9 million.

Measured in Canadian dollars, for the three months ended December 31, 2012, Liberty Utilities (Central)'s revenue from water treatment and wastewater distribution totalled $2.1 million, as compared to $2.4 million during the same period in 2011.

Measured in Canadian dollars, for the three months ended December 31, 2012, operating expenses, excluding natural gas purchases, totalled $6.3 million, as compared to $1.2 million during the same period in 2011.

Measured in Canadian dollars, for the three months ended December 31, 2012, Liberty Utilities (Central)'s operating profit totalled $4.3 million as compared to $1.2 million in the same period in 2011.

In the June 30, 2012 Interim MD&A, guidance was provided on the Liberty Utilities (Central)'s expected operating results over the 12 month period ending June 30, 2013. For the three months ended December 31, 2012, Midwest Gas Utilities' EBITDA of U.S. $3.9 million did not meet the guidance EBITDA of U.S. $4.6 million. The decreased EBITDA was due primarily to lower than expected natural gas usage in the states of Missouri, Illinois, and Iowa with Central recording actual usage of 2,001,050 MMBTU compared to the guidance of 2,006,230 MMBTU. A portion of the decreased usage results from actual active natural gas connections being 82,050 compared to the guidance of 83,223 active natural gas connections a difference of 928 active connections.

The table below represents forward looking information that was provided as at August 9, 2012 and which summarizes the expected operating results for the Liberty Utilities (Central)'s gas utilities for the next two quarters:

Expected short term metrics	2013 Q1	2013 Q2
Missouri	$4.0	$1.3
Illinois	2.6	0.8
Iowa	0.9	0.2
Total EBITDA (U.S.$ millions)	$7.5	$2.3
Customers	83,336	83,358
Normalized MMBTU	4,175,086	1,542,906

Readers are cautioned that actual results may vary from the above noted forward-looking information. Management is providing this forward looking information to allow readers to better understand the actual EBITDA of the acquired utilities as they occur in the year following acquisition, including the variation in financial performance that might be expected from quarter to quarter. Further, the forward-looking financial information does not include information for net earnings resulting from the acquisitions as it does not include information related to interest, depreciation, amortization and income taxes. Therefore, this forward-looking information may not be suitable or appropriate for other purposes other than as described herein. Management intends to report actual EBITDA results compared to this forward-looking information. Management does not intend to further update this financial information except as may be required by law.

Liberty Utilities: East Region

	From the acquisition date to December 31[1] 2012	2011
Number of Active Natural Gas Connections		
Residential	76,350	-
Commercial and Industrial	11,300	-
Total Active Natural Gas Connections	**87,650**	**-**
Number of Active Electric Connections		
Residential	35,450	-
Commercial and Industrial	7,800	-
Total Active Electric Connections	**43,250**	**-**
Customer Usage (GW-hrs)		
Residential	143.4	-
Commercial and Industrial	331.1	-
Total Customer Usage (GW-hrs) [2]	**474.5**	**-**
Customer Usage (MMBTU)		
Residential	1,552,200	-
Commercial and Industrial	3,176,200	-
Total Customer Usage (MMBTU) [2]	**4,728,400**	**-**

[1] Granite State Electric Utility and EnergyNorth Gas Utility were acquired on July 3, 2012.
[2] Represents MMBTU and GW-hrs since July 3, 2012 acquisition date.

Liberty Utilities (East) is comprised of Liberty Utilities' operations in New Hampshire. Liberty Utilities (East) acquired its natural gas and electric distribution utilities on July 3, 2012 and, accordingly, there are no results for the utilities for the corresponding period in 2011.

Liberty Utilities (East) operates a regulated natural gas utility and an electric retail distribution company, both located in New Hampshire. Liberty Utilities (East) provides regulated natural gas services to approximately 87,650 active connections and regulated electric retail distribution service to approximately 43,250 active connections. Liberty Utilities (East) reports active connections, exclusive of vacant connections rather than total connections.

From the acquisition date of July 3, 2012 to December 31, 2012, Liberty Utilities (East)'s electricity usage totalled 474.5 GW-hrs and natural gas usage totalled 4,728,400 MMBTU.

	From the acquisition date to December 31[1] 2012 U.S. $ (millions)	From the acquisition date to December 31[1] 2011 U.S. $ (millions)	From the acquisition date to December 31[1] 2012 Can $ (millions)	From the acquisition date to December 31[1] 2011 Can $ (millions)
Electricity Assets for regulatory purposes	**88.4**	-		
Natural Gas for regulatory purposes	**263.4**	-		
Revenue				
Utility electricity sales and distribution	**$ 36.8**	$ -	**$ 36.7**	$ -
Utility natural gas sales and distribution	**50.3**	-	**49.9**	-
Other Revenue	**0.1**	-	**0.1**	-
	87.2	-	**86.7**	-
Less:				
Cost of Sales – Electricity	**(24.4)**	-	**(24.3)**	-
Cost of Sales – Natural Gas[2]	**(24.0)**	-	**(23.8)**	-
	$ 38.8	$ -	**$ 38.6**	$ -
Expenses				
Operating expenses	**(30.4)**	-	**(30.2)**	-
Other Income	**0.4**		**0.4**	
Division operating profit[1]	**$ 8.8**	**$ -**	**$ 8.8**	**$ -**

[1] Granite State Electric Utility and EnergyNorth Gas Utility were acquired on July 3, 2012.
[2] Natural Gas costs are shown net of U.S. $4.5 million regulatory authorized deferral related to an under recovery of actual gas costs.

2012 Annual Operating Results

Liberty Utilities (East) has investments in electricity assets for regulatory purposes of U.S. $88.4 million, and natural gas assets for regulatory purposes of U.S. $263.4 million as at December 31, 2012, as compared to U.S. $nil and U.S. $nil, respectively as at December 31, 2011.

From the date of acquisition to December 31, 2012, Liberty Utilities (East)'s revenue totalled U.S. $87.2 million as a result of the acquisitions of Granite State Electric Utility and EnergyNorth Gas Utility on July 3, 2012.

From the date of acquisition to December 31, 2012, Liberty Utilities (East)'s revenue from utility electricity sales totalled U.S. $36.8 million. The cost of electricity is passed through to Liberty Utilities (East)'s customers. As a result, the division compares 'net utility electricity sales' (revenue from electricity sales less fuel and purchased power costs) as a more appropriate measure of the division's results. From the date of acquisition to December 31, 2012, net electricity utility sales for Liberty Utilities (East) totalled U.S. $12.4 million.

From the date of acquisition to December 31, 2012, Liberty Utilities (East)'s revenue from natural gas sales and distribution totalled U.S. $50.3 million. The cost of natural gas by Liberty Utilities (East) is passed through to Liberty Utilities (East)'s customers. As a result, the division compares 'net utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. From the date of acquisition to December 31, 2012, net utility natural gas sales and distribution revenue for Liberty Utilities (East) totalled U.S. $26.3 million.

From the date of acquisition to December 31, 2012, electricity purchases for Liberty Utilities (East) totalled U.S. $24.4 million, and natural gas purchases totalled U.S. $24.0 million.

From the date of acquisition to December 31, 2012, operating expenses, excluding electricity and natural gas purchases, totalled U.S. $30.4 million.

From the date of acquisition to December 31, 2012, Liberty Utilities (East)'s operating profit totalled U.S. $8.8 million.

Measured in Canadian dollars, from the date of acquisition to December 31, 2012, Liberty Utilities (East)'s revenue from utility electricity sales totalled $36.7 million and utility natural gas sales totalled $49.9 million. Measured in Canadian dollars, from the date of acquisition to December 31, 2012, Liberty Utilities (East)'s net utility electricity sales and distribution revenue totalled $12.4 million and net utility natural gas sales and distribution revenue totalled $26.1 million.

Measured in Canadian dollars, from the date of acquisition to December 31, 2012, Liberty Utilities (East)'s electricity purchases totalled $24.3 million, and natural gas purchases totalled $23.8 million.

Measured in Canadian dollars, from the date of acquisition to December 31, 2012, Liberty Utilities (East)'s operating expenses excluding electricity and natural gas purchases totalled $30.2 million.

Measured in Canadian dollars, from the date of acquisition to December 31, 2012, Liberty Utilities (East)'s operating profit totalled $8.8 million.

	Three months ended December 31,	
	2012	2011
Customer Usage (GW-hrs)		
Residential	64.1	-
Commercial and Industrial	148.0	-
Total Customer Usage (GW-hrs)	**212.1**	**-**
Customer Usage (MMBTU)		
Residential	1,206,900	-
Commercial and Industrial	2,059,900	-
Total Customer Usage (MMBTU)	**3,266,800**	**-**

For the three months ended December 31, 2012, Liberty Utilities (East)'s electricity usage totalled 212.1 GW-hrs and natural gas usage totalled 3,266,800 MMBTU.

	Three months ended December 31		Three months ended December 31	
	2012	2011	2012	2011
	U.S. $ (millions)	U.S. $ (millions)	**Can $ (millions)**	Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 17.7**	$ -	**$ 17.6**	$ -
Utility natural gas sales and distribution	**38.1**	-	**37.7**	-
Other Revenue	**-**	-	**-**	-
	55.8	-	**55.3**	-
Less:				
Cost of Sales – Electricity	**(12.3)**	-	**(12.2)**	-
Cost of Sales – Natural Gas[1]	**(21.9)**	-	**(21.7)**	-
	$ 21.6	$ -	**$ 21.4**	$ -
Expenses				
Operating expenses	**(16.5)**	-	**(16.3)**	-
Other income	**0.4**		**0.4**	
Division operating profit[1]	**$ 5.5**	$ -	**$ 5.5**	$ -

[1] Natural Gas costs are shown net of U.S. $1.7 million regulatory authorized deferral related to an under recovery of actual gas costs.

2012 Fourth Quarter Operating Results

For the three months ended December 31, 2012, Liberty Utilities (East)'s revenue totalled U.S. $55.8 million.

For the three months ended December 31, 2012, Liberty Utilities (East)'s revenue from utility electricity sales totalled U.S. $17.7 million. The cost of electricity is passed through to Liberty Utilities (East)'s customers. As a result, the division compares 'net utility electricity sales' (revenue from electricity sales less fuel and purchased power costs) as a more appropriate measure of the division's results. For the three months ended December 31, 2012, net electricity utility sales for Liberty Utilities (East) totalled U.S. $5.4 million.

For the three months ended December 31, 2012, Liberty Utilities (East)'s revenue from natural gas sales and distribution totalled U.S. $38.1 million. The cost of natural gas by Liberty Utilities (East) is passed through to Liberty Utilities (East)'s customers. As a result, the division compares 'net utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. For the three months ended December 31, 2012, net utility natural gas sales and distribution revenue for Liberty Utilities (East) totalled U.S. $16.2 million.

For the three months ended December 31, 2012, electricity purchases for Liberty Utilities (East) totalled U.S. $12.3 million, and natural gas purchases totalled U.S. $21.9 million.

For the three months ended December 31, 2012, operating expenses, excluding electricity and natural gas purchases, totalled U.S. $16.5 million.

For the three months ended December 31, 2012, Liberty Utilities (East)'s operating profit totalled U.S. $5.5 million.

Measured in Canadian dollars, for the three months ended December 31, 2012, Liberty Utilities (East)'s revenue from utility electricity sales totalled $17.6 million and utility natural gas sales totalled $37.7 million. Measured in Canadian dollars, for the three months ended December 31, 2012, Liberty Utilities (East)'s net utility electricity sales and distribution revenue totalled $5.4 million and net utility natural gas sales and distribution revenue totalled $16.0 million.

Measured in Canadian dollars, for the three months ended December 31, 2012, Liberty Utilities (East)'s electricity purchases totalled $12.2 million, and natural gas purchases totalled $21.7 million.

Measured in Canadian dollars, for the three months ended December 31, 2012, Liberty Utilities (East)'s operating expenses excluding electricity and natural gas purchases totalled $16.3 million.

Measured in Canadian dollars, for the three months ended December 31, 2012, Liberty Utilities (East)'s operating profit totalled $5.5 million.

In the June 30, 2012 Interim MD&A, guidance was provided on Granite State Electric Utility and EnergyNorth Gas Utility's expected operating results over the 12 month period ending June 30, 2013. For the three months ended December 31, 2012, Granite State Electric Utility's EBITDA of U.S. $0.5 million was lower than the guidance EBITDA of U.S. $0.8 million. The decreased EBITDA was due to lower than expected electricity usage by residential, commercial and industrial connections. Actual electricity usage was 212.1 GW-hrs compared to the guidance of 224.6 GW-hrs. Actual active electric connections were 43,250 compared to the previous guidance of 43,259 active electric connections.

For the three months ended December 31, 2012, EnergyNorth Gas Utility's EBITDA of U.S. $5.0 million met the guidance EBITDA of U.S. $5.0 million. The EBITDA for the fourth quarter was a result of higher than expected connections for the quarter offset by lower than expected natural gas usage by residential, commercial, and industrial connections as compared to the previous guidance. Actual MMBTU was 3,266,800 compared to the previous guidance of 3,787,000. Actual active natural gas connections were 87,650 compared to the previous guidance of 86,832 active natural gas connections.

The table below represents forward looking information that was provided as at August 9, 2012 and which summarizes the expected operating results for Granite State Electric Utility and EnergyNorth Gas Utility over the next two quarters:

Expected short term metrics	2013 Q1	2013 Q2
Granite State Electric Utility:		
Customers	43,312	43,365
Normalized MW-hrs	238,200	227,500
EBITDA (U.S.$ millions)	$1.8	$1.0
EnergyNorth Gas Utility		
Customers	87,263	87,696
Normalized MMBTU	5,629,000	2,462,000
EBITDA (U.S. $ millions)	$12.8	$3.9

Readers are cautioned that actual results may vary from the above noted forward-looking information. Management is providing this forward looking information to allow readers to better understand the actual EBITDA of the acquired utilities as they occur in the year following acquisition, including the variation in financial performance that might be expected from quarter to quarter. Further, the forward-looking financial information does not include information for net earnings resulting from the acquisitions as it does not include information related to interest, depreciation, amortization and income taxes. Therefore, this forward-looking information may not be suitable or appropriate for other purposes other than as described herein. Management intends to report actual EBITDA results compared to this forward-looking information. Management does not intend to further update this financial information except as may be required by law.

Outlook – Liberty Utilities

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

On May 31, 2012, Liberty Utilities (West) filed a general rate case with the Arizona Corporation Commission related to the Rio Rico facilities seeking, among other things, an increase in EBITDA by U.S. $1.0 million over

2011 results if approved as filed. The application seeks recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application seeks a mechanism that helps mitigate the effects of regulatory lag on capital investment. The new rates are expected to be implemented in the second half of 2013.

On February 17, 2012, Liberty Utilities (West) filed a general rate case and on November 29, 2012, approval of the All Parties General Rate Case Settlement ("Settlement") was received from the CPUC. As an element of the decision, a revenue decoupling mechanism and a vegetation management memorandum account was agreed upon. The revenue decoupling mechanism will decouple base revenues from fluctuations caused by weather and economic factors. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses, one of the largest expenses of the utility. Primarily as a result of the rate case at the Calpeco Electric Utility, additional EBITDA of $7.1 million is expected in 2013.

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

In the first half of 2013, Liberty Utilities (East)'s electric utility will file a rate case with the NHPUC seeking an increase in distribution base rates for Granite State Electric Utility. The filing is based on a 2012 test year, with revenues and expenses adjusted to reflect known and measurable changes. In addition, Granite State Electric Utility will request approval to implement a "rate year" step adjustment to reflect certain capital additions to rate base after the test year. Among other things, Granite State Electric Utility will also seek to continue current cost-recovery tracking mechanisms, including long-term continuation of the REP/VMP Program and a modification to allow for recovery of pre-staging personnel and equipment for qualifying storms. The case is expected to be concluded in mid-2014; in accordance with general New Hampshire regulatory practice, interim rates are expected to be implemented on or about July 1, 2013.

APUC: Corporate and Other Expenses

	Three months ended December 31		Year ended December 30	
	2012	2011	**2012**	2011
Corporate and other expenses:	**(millions)**	(millions)	**(millions)**	(millions)
Administrative expenses	**$ 5.4**	$ 4.8	**$ 19.6**	$ 17.5
(Gain)/Loss on foreign exchange	**(1.6)**	0.4	**(0.6)**	(0.7)
Interest expense	**11.3**	7.6	**35.9**	30.4
Interest, dividend and other Income	**(0.4)**	(0.8)	**(2.1)**	(3.0)
Write down of long lived assets	**-**	15.2	**-**	15.2
Acquisition-related costs	**1.3**	1.2	**7.7**	3.0
(Gain)/Loss on derivative financial instruments	**(0.4)**	1.6	**(0.2)**	5.8
Income tax recovery	**(6.6)**	(6.0)	**(13.6)**	(22.5)

2012 Annual Corporate and Other Expenses

During the year ended December 31, 2012, administrative expenses totalled $19.6 million, as compared to $17.5 million in the same period in 2011. The expense increase in the year ended December 31, 2012 primarily results from additional personnel, increased wages, additional costs required to administer APUC's operations, share based compensation expense and other costs as compared to the same period in 2011.

For the year ended December 31, 2012, interest expense totalled $35.9 million as compared to $30.4 million in the same period in 2011. The increased interest expense is due to new indebtedness as a result of the U.S. $225 million private placement used to fund a portion of the New Hampshire and Midwest Gas Utilities acquisitions, the $135 million senior unsecured debentures placed in the third quarter of 2011 and an $1.7 million in 2012 related to the Quebec water lease litigation as compared to the same period in 2011. These amounts were partially offset by reduced interest expense related to convertible debentures due to the conversion of the Series 1A Debentures in the prior year and the Series 2A Debentures in the first quarter of 2012 and lower interest expense related to the Air Source debt which was retired in 2011.

For the year ended December 31, 2012, interest, dividend and other income totalled $2.1 million as compared to $3.0 million in the same period in 2011. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

For the year ended December 31, 2012, acquisition related costs totalled $7.7 million as compared to $3.0 million in the same period in 2011. The increase was primarily driven by the closing of Sandy Ridge Wind Facility on July 1, 2012, Granite State Electric Utility and EnergyNorth Gas Utility acquisitions on July 3, 2012, the Midwest Gas Utilities on August 1, 2012, and Minonk and Senate Facilities on December 10, 2012.

An income tax recovery of $13.6 million was recorded in the year ended December 31, 2012, as compared to a recovery of $22.5 million during the same period in 2011. The income tax recovery for the year ended December 31, 2012 primarily resulted from the recognition of deferred credits from the utilization of deferred income tax assets recognized at the time of the Unit Exchange Offer, non-taxable inter-corporate dividends, changes in tax rates, losses in subsidiaries and production tax credits.

2012 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2012, administrative expenses totalled $5.4 million, as compared to $4.8 million in the same period in 2011. The expense increase in the quarter ended December 31, 2012 primarily results from additional personnel, increased wages, additional costs required to administer APUC's operations, share based compensation expense and other costs as compared to the same period in 2011.

For the quarter ended December 31, 2012, interest expense totalled $11.3 million as compared to $7.6 million in the same period in 2011. The increased interest expense is due new indebtedness as a result of the U.S. $225 million private placement used to fund a portion of the EnergyNorth Gas Utility, Granite State Electric Utility, and Midwest Gas Utilities acquisitions, and the $135 million senior unsecured debentures placed in the third quarter of 2011. These amounts were partially offset by reduced interest expense related to convertible debentures due to the conversion of the Series 1A Debentures in the prior year and the Series 2A Debentures in the first quarter of 2012.

For the quarter ended December 31, 2012, interest, dividend and other income totalled $0.4 million, as compared to $0.8 million in the same period in 2011. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

An income tax recovery of $6.6 million was recorded in the three months ended December 31, 2012, as compared to a recovery of $6.0 million during the same period in 2011. The income tax recovery for the three months ended December 31, 2012 primarily resulted from the recognition of deferred credits from the utilization of deferred income tax assets recognized at the time of the Unit Exchange Offer, non-taxable inter-corporate dividends, changes in tax rates, losses in subsidiaries and production tax credits.

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

EBITDA is a non-GAAP metric used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of depreciation and amortization expense, income tax expense or recoveries, acquisition costs, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

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

		Three months ended December 31 2012		2011		Year ended December 31 2012		2011
		(millions)		(millions)		**(millions)**		(millions)
Net earnings/(loss) attributable to Shareholders	**$**	**6.4**	$	(8.5)	**$**	**14.5**	$	23.4
Add (deduct):								
Net earnings attributable to the non-controlling interest		**6.2**		0.5		**7.4**		3.9
Loss from discontinued operations		**0.1**		0.9		**1.2**		0.8
Income tax recovery		**(6.6)**		(6.0)		**(13.6)**		(22.5)
Interest expense*		**10.2**		7.6		**34.8**		30.4
Acquisition costs		**1.3**		1.2		**7.7**		3.0
Write down of long-lived assets		**-**		15.2		**-**		15.2
Quebec water lease litigation		**-**		-		**0.5**		-
(Gain)/Loss on derivative financial instruments		**(0.4)**		1.6		**(0.2)**		5.8
(Gain)/Loss on foreign exchange		**(1.6)**		0.4		**(0.6)**		(0.7)
Depreciation and amortization		**17.8**		11.4		**54.5**		44.4
Adjusted EBITDA	**$**	**33.4**	$	24.3	**$**	**106.2**	$	103.7

* Interest expense is net of AFUDC Allowance for equity funds. See note 1(i) of notes to the financial statements.

For the year ended December 31, 2012, Adjusted EBITDA totalled $106.2 million as compared to $103.7 million, an increase of $2.5 million or 2% as compared to the same period in 2011. For the quarter ended December 31, 2012, Adjusted EBITDA totalled $33.4 million as compared to $24.3 million, an increase of $9.1 million or 37% as compared to the same period in 2011.

The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

		Three months ended December 30		Year ended December 30
		(millions)		**(millions)**
Comparative Prior Period Adjusted EBITDA	$	24.3	$	103.7
Significant Changes:				
Liberty Utilities (West) - (Reduced)/Increased electricity sales due to different weather patterns compared to prior year		1.9		(3.5)
Liberty Utilities (Central) – Midwest Gas Utilities acquisition		3.7		4.4
Liberty Utilities (East) –EnergyNorth Gas Utility acquisition		4.7		6.1
Liberty Utilities (East) –Granite State Electric Utility acquisition		0.4		2.3
Renewable – Decreased hydrologic resource		-		(3.8)
Renewable - Acquisition of U.S. Wind assets		1.9		2.0
Renewable – St Leon – Reduced wind resource compared to prior year		(1.4)		(0.5)
Renewable – St Leon II – Operations from facility expansion		0.7		1.1
Renewable – Tinker Hydro/AES - Increased demand for retail sales overshadowed by higher energy costs		(1.0)		(1.7)
Thermal – Windsor Locks – Reduced energy sales due to market conditions		0.1		(2.9)
Thermal – EFW – Lower production due to expiry of Region of Peel contract		(1.2)		(0.7)
Administrative expense		(0.5)		(2.1)
Increased/(decreased) results from the stronger U.S. dollar		(0.7)		0.6
Other		0.5		1.2
Current Period Adjusted EBITDA	$	33.4	$	106.2

Reconciliation of adjusted net earnings to net earnings

Adjusted net earnings is a non-GAAP metric used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses and are viewed as not directly related to a company's operating performance. Net earnings of APUC can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps and energy forward purchase contracts as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. APUC uses adjusted net earnings to assess its performance without the effects of gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, litigation expenses and write down of intangibles and property, plant and equipment as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP.

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

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

	Three months ended December 31				Year ended December 31			
		2012		2011		2012		2011
		(millions)		(millions)		**(millions)**		(millions)
Net earnings/(loss) attributable to Shareholders	**$**	**6.4**	$	(8.5)	**$**	**14.5**	$	23.4
Add (deduct):								
Loss from discontinued operations, net of tax		**0.1**		0.9		**1.2**		0.8
(Gain)/Loss on derivative financial instruments, net of tax		**(0.3)**		1.0		**(0.2)**		3.9
Write down of long-lived assets, net of tax		**-**		9.1		**-**		9.1
Quebec water lease litigation and interest, net of tax		**-**		-		**1.5**		-
(Gain)/Loss on foreign exchange, net of tax		**(1.6)**		0.4		**(0.6)**		(0.7)
Acquisition costs, net of tax		**0.8**		0.7		**4.7**		1.8
Adjusted net earnings	**$**	**5.4**	$	3.6	**$**	**21.1**	$	38.3
Adjusted net earnings per share	**$**	**0.03**	$	0.03	**$**	**0.14**	$	0.33

For the year ended December 31, 2012, adjusted net earnings totalled $21.1 million as compared to adjusted net earnings of $38.3 million, a decrease of $17.2 million as compared to the same period in 2011. The decrease in adjusted net earnings for the year ended December 31, 2012 is primarily due to higher depreciation and amortization expense, higher interest expense, higher administration costs and decreased income tax recovery amounts, partially offset by higher income from operations, and interest and dividends as compared to the same period in 2011.

For the three months ended December 31, 2012, adjusted net earnings totalled $5.4 million as compared to adjusted net earnings of $3.6 million, an increase of $1.8 million as compared to the same period in 2011. The increase in adjusted net earnings for the three months ended December 31, 2012 is primarily due to increased earnings from operations, and increased income tax recovery amounts, partially offset by higher depreciation and amortization expense, higher administration costs, and higher interest expense as compared to the same period in 2011.

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

Adjusted funds from operations is a non-GAAP metric used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses and are viewed as not directly related to a company's operating performance. Cash flows from operating activities of APUC can be impacted positively or negatively by changes in working capital balances, acquisition and litigation expense. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. APUC uses adjusted funds from operations to assess its performance without the effects of changes in working capital balances, acquisition and litigation expense as these are not reflective of the long-term performance of the underlying businesses of APUC. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP.

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

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

	Three months ended December 31 2012 (millions)	2011 (millions)	Year ended December 31 2012 (millions)	2011 (millions)
Cash flows from operating activities	**$ 16.1**	$ 1.4	**$ 63.0**	$ 69.7
Add (deduct):				
Changes in non-cash operating items	**7.2**	11.6	**3.9**	1.5
Cash provided/(used) in discontinued operation	**0.4**	(1.5)	**0.4**	(1.5)
Quebec water lease litigation accrual	**1.9**	-	**1.9**	-
Acquisition costs	**1.3**	1.2	**7.7**	3.0
Adjusted funds from operations	**$** 26.9	$ 12.7	**$ 76.9**	$ 72.7
Adjusted funds from operations per share	**$ 0.16**	$ 0.10	**$ 0.52**	$ 0.62

For the year ended December 31, 2012, adjusted funds from operations totalled $76.9 million as compared to adjusted funds from operations of $72.7 million, an increase of $4.2 million as compared to the same period in 2011.

For the three months ended December 31, 2012, adjusted funds from operations totalled $26.9 million as compared to adjusted funds from operations of $12.7 million, an increase of $14.2 million as compared to the same period in 2011.

Summary of Property, Plant and Equipment Expenditures

	Three months ended December 31 2012 (millions)	2011 (millions)	Year ended December 31 2012 (millions)	2011 (millions)
APCo				
Renewable Energy Division				
Capital expenditures	**$ 7.5**	$ 6.7	**$ 21.1**	$ 25.6
Acquisition or development of new operating facilities	**217.0**	-	**245.7**	-
Total	**$ 224.5**	$ 6.7	**$ 266.8**	$ 25.6
Thermal Energy Division				
Capital expenditures, net	**$ (2.0)**	$ 4.5	**$ 10.3**	$ 13.6
Total	**$ (2.0)**	$ 4.5	**$ 10.3**	$ 13.6
LIBERTY UTILITIES				
West				
Capital Investment in regulatory assets	**$ 9.6**	$ 9.3	**$ 23.2**	$ 20.4
Acquisition of new operating utilities	**-**	2.9	**-**	100.1
Total	**$ 9.6**	$ 12.2	**$ 23.2**	$ 120.5
Central				
Capital Investment in regulatory assets	**$ 8.8**	$ 0.2	**$ 10.8**	$ 0.8
Acquisition of new operating utilities	**-**	-	**128.9**	-
Total	**$ 8.8**	$ 0.2	**$ 139.7**	$ 0.8
East				
Capital Investment in regulatory assets	**$ 8.9**	$ -	**$ 12.5**	$ -
Acquisition of new operating utilities	**-**	-	**295.3**	-
Total	**$ 8.9**	$ -	**$ 307.8**	$ -
CONSOLIDATED				
Total APCo				
Capital expenditures	**$ 5.5**	$ 11.2	**$ 31.4**	$ 39.2
Acquisition or development of new operating facilities	**217.0**	-	**245.7**	-
Total Liberty Utilities				
Capital investment in regulatory assets	**27.3**	9.5	**46.5**	21.2
Acquisition of operating entities	**-**	2.9	**424.2**	100.1
Corporate	**-**	-	**-**	0.4
Total	**$ 249.8**	$ 23.6	**$ 747.8**	$ 160.9

APUC's consolidated capital expenditures in the year ended December 31, 2012 increased as compared to the same period in 2011 primarily due to APCo's acquisition of the Gamesa Wind Facilities and Liberty Utilities' acquisitions of EnergyNorth Gas Utility, Granite State Electric Utility and the Midwest Gas Utilities.

Property, plant and equipment expenditures for the 2013 fiscal year are anticipated to be between $130 million and $145 million. Capital expenditures for Liberty Utilities include: approximately $34 million at Liberty Utilities

(East) related maintenance and installation pipe in New Hampshire; approximately $20 million at Liberty Utilities (Central) related to pipe expansion and replacement; and, approximately $24 million at Liberty Utilities (West) related to major line rebuilds for the Calpeco Electric Utility and meter and overall improvements related to the water utilities. For APCo, capital expenditures includes: approximately $10 million related to the APCo Renewable Energy Division, $45 million related the development of the Cornwall Solar project; and, approximately $3 million related to the APCo Thermal Division primarily related to routine maintenance at the Windsor Locks facility and a turbine overhaul at the EFW facility.

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.

2012 Annual Property Plant and Equipment Expenditures

During the year ended December 31, 2012, APCo incurred capital expenditures of $31.4 million, as compared to $39.2 million during the comparable period in 2011 in addition to $245.7 million to acquire operating entities.

During the year ended December 31, 2012, APCo's Renewable Energy Division spent $21.1 million in capital expenditures as compared to $25.6 million in the comparable period in 2011. The capital expenditures primarily relate to the St. Leon II expansion, capitalized maintenance and upgrades at the Tinker, Long Sault, and Clement Dam hydro facilities, and project costs related to the Cornwall Solar, St. Damase and Amherst Island developments. Additionally, APCo's Renewable Energy Division spent $245.7 million on property plant and equipment in the acquisition of Sandy Ridge, Minonk, and Senate Wind Facilities. APCo's Thermal Energy Division net capital expenditures were $10.3 million, as compared to $13.6 million in the comparable period in 2011. The capital expenditures primarily relate to the Windsor Locks repowering and the major maintenance at the Sanger facility offset by two one-time non-recurring items: the $6.5 million grant from the State of Connecticut; and a $2.4 million heat and power ITC sponsored by the U.S. Federal Government.

During the year ended December 31, 2012, Liberty Utilities invested $46.5 million in capital expenditures as compared to $21.2 million during the comparable period in 2011. Additionally, Liberty Utilities spent $424.2 million to acquire operating entities as compared to $100.1 million during the comparable period in 2011. Liberty Utilities (West)'s spend was primarily related to maintenance and refurbishment needs at the Calpeco Electric Utility and the expansion of the LPSCo facility. Liberty Utility (Central)'s $10.8 million in capital expenditures was primarily a result of the $128.9 million acquisition of the Midwest Gas Utility. Liberty Utility (East)'s $12.5 million in capital expenditures was primarily a result of the $295.3 million acquisition of Granite State Electric Utility and EnergyNorth Gas Utility.

2012 Fourth Quarter Property Plant and Equipment Expenditures

During the quarter ended December 31, 2012, APCo incurred capital expenditures of $5.5 million, as compared to $11.2 million during the comparable period in 2011 in addition to $217.0 million to acquire operating entities.

During the quarter ended December 31, 2012, APCo Renewable Energy Division's capital expenditures were $7.5 million, as compared to $6.7 million in the comparable period in 2011. The capital expenditures primarily relate to the capitalized maintenance of the Long Sault hydro facilities, and project costs related to the Cornwall Solar, St. Damase and Amherst Island developments. APCo Thermal Energy Division's net capital expenditures were ($2.0) million as a result of a $2.4 million ITC sponsored by the U.S. Federal Government related to the repowering of the facility earlier in the year.

During the quarter ended December 31, 2012, Liberty Utilities invested $27.3 million in capital expenditures as compared to $9.5 million during the comparable period in 2011. Liberty Utilities (West)'s spend was primarily related to maintenance and refurbishment needs at the Calpeco Electric Utility and the expansion of the LPSCO facility. Liberty Utility (Central)'s $8.8 million in capital expenditures was primarily a result of the acquisition of the Midwest Gas Utility. Liberty Utility (East)'s $8.9 million in capital expenditures was primarily a result of the Granite State Electric Utility and EnergyNorth Gas Utility acquisition.

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C93), APCo's Renewable Energy Division completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. Out of these, nine remedial plans have been submitted to the Quebec government and two are undergoing options analysis by APCo. The nine remedial plans have been accepted by the Quebec government and one is still being reviewed.

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

	Total	2013	2014	2015	2016
Future Estimated Bill C-93 Capital Expenditures	16,900	5,600	8,000	3,000	300

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

- APCo's proposed remediation plan for the Mont Laurier facility has been accepted by the Quebec government. APCo received the Certificate of Authorization from the Quebec government in November 2011. APCo completed the majority of the on-site remediation work in 2012 at a capital cost of approximately $0.3 million. Phase two of the on-site remediation work is scheduled for Q3-Q4 of 2013 at an estimated cost of $0.1 million.
- APCo completed the dam safety evaluation for the Donnacona facility and is continuing to explore alternative engineering designs to minimize the cost of the remediation work. APCo is now pursuing a design that may result in a cost savings of 20% of the original estimates. APCo completed the engineering in 2012 and submitted the rehabilitation plan to the Quebec government to obtain the Certificate of Authorization. The remedial on-site work is anticipated to start in mid to late 2013 and be completed in 2014.
- The dam safety study and a detailed condition assessment for the St. Alban facility have been completed. APCO is reviewing the results of the condition assessment and expects to finalize the remediation plan for this dam in 2012. APCo anticipates engineering and regulatory review to be performed in 2012 and 2013, with remedial work in 2014 to 2015.
- APCo is presently reviewing options with respect to the Belleterre facility including the removal of several small dams that are not required for power generation. APCo anticipates completion of any required work on these dams by 2015.
- Engineering for the Riviere-du-Loup facility was completed in Q4 of 2012. Following a geotechnical investigation the remediation work is now estimated at $1.1million.
- The dam remediation work related to Chute Ford was completed in 2012 while the work related to the St. Raphael facility is anticipated to be completed in 2013.

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

Liquidity and Capital Reserves

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

Bank Credit Facilities

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries as at December 31, 2012 under the Facilities:

	As at December 31, 2012				As at Sept 30, 2012	As at Dec 31, 2011
	APUC	APCo	Liberty Utilities	Total	Total	Total
	(millions)	(millions)	(millions)	(millions)	(millions)	(millions)
Committed Facilities	$ 30.0	$ 200.0	$ 99.5	$ **329.5**	$ **253.3**	$ 120.0
Funds drawn on Facilities	-	(27.1)	(27.4)	(54.5)	(80.6)	-
Letters of Credit issued	(1.3)	(47.4)	(2.0)	(50.7)	(52.2)	(39.6)
Funds available for draws on the Facilities	**$ 28.7**	**$ 125.5**	**$ 70.1**	**$ 224.3**	**$ 120.5**	**$ 80.4**
Cash on Hand				53.1	16.4	72.9
Total liquidity and capital reserves	**$ 28.7**	**$ 125.5**	**$ 70.1**	**$ 277.4**	**$ 136.9**	**$ 153.3**

On November 19, 2012, APUC entered into an agreement for a three year $30.0 million senior unsecured revolving credit facility ("APUC Facility") with a Canadian chartered bank. The credit facility will be used for general corporate purposes and will provide APUC with additional financial flexibility. As at December 31, 2012, the APUC facility was undrawn and had $1.3 million of outstanding letters of credit.

During the fourth quarter of 2012, APCo concluded discussions with its banking syndicate to increase its senior credit facility (the "APCo Facility") to $200 million. The amendment to the facility also resulted in security previously held over certain APCo entities to be released by the banking syndicate and the facility is now unsecured. As at December 31, 2012, APCo had drawn $27.1 million had $47.4 million in outstanding letters of credit under the APCo Facility.

During the third quarter of 2012, Liberty Utilities senior unsecured revolving credit facility (the "Liberty Facility") was increased to $100 million. The Liberty Facility is unsecured and is for a three year term with a maturity of January 18, 2015. As at December 31, 2012, Liberty Utilities had $27.4 million was drawn to support working capital requirements and had $2.0 million of outstanding letters of credit under the Liberty Facility.

Long Term Debt

On December 3, 2012, APCo issued $150 million 4.82% senior unsecured debentures with a maturity date of February 15, 2021 pursuant to a private placement in Canada and the United States. The APCo Debentures were sold at a price of $99.94 per $100.00 principal amount, resulting in an effective yield to maturity of 4.83% per annum. Concurrent with the offering, APCo entered into a cross currency swap, coterminous with the APCo Debentures, to convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of 4.4%. Net proceeds from the APCo Debentures were used primarily to fund the 400MW investment in U.S wind portfolio assets which closed on December 10, 2012.

On January 1, 2013, in conjunction with the acquisition of the Shady Oaks Wind Facility, APCo assumed a U.S. $150 million dollar variable rate long term credit facility. The facility is secured by the assets of the Wind Farm. APCo will be required to make a one-time principal payment of U.S. $25 million in the second quarter of 2013 and semi-annual principal payments ranging between U.S. $3 million and U.S. $6 million thereafter. The facility matures in 2026. Funds advanced against the facility are repayable at any time without penalty. APCo intends to refinance the facility in a manner consistent with APCo's long term capital structure of between 45% and 50% debt. The permanent financing is expected to be issued through APCo's existing unsecured bond platform.

During the third quarter, Liberty Utilities completed a U.S. $225 million private placement debt financing. The financing was closed in two tranches contemporaneously with the closing of the Granite State Electric Utility and EnergyNorth acquisitions. The notes are senior unsecured notes with an average life maturity of over ten years and a weighted average coupon of 4.38%. The notes have been assigned a rating of "BBB high" by DBRS Limited. Proceeds from the private placement were used to partially fund the aforementioned acquisitions.

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

On March 14, 2013, Liberty Utilities entered in an agreement for a U.S. $100 million variable rate short-term acquisition facility with a U.S. Bank. The loan facility is available for acquisition and general corporate purposes and matures on December 31, 2013.

Contractual Obligations

Information concerning contractual obligations as of December 31, 2012 is shown below:

	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
	(millions)	(millions)	(millions)	(millions)	(millions)
Long-term debt obligations[1]	$ 770.9	1.8	58.5	14.9	695.7
Advances in aid of construction	$ 72.2	0.6	-	-	71.6
Interest on long-term debt obligations	$ 329.8	41.1	80.4	71.6	136.7
Purchase obligations	$ 135.6	135.6	-	-	-
Environmental Obligations	$ 59.8	2.4	32.2	15.2	10.0
Derivative financial instruments:					
Cross Currency Swap	$ 2.1	-	-		2.1
Interest rate swap	$ 4.8	2.0	2.8	-	-
Energy derivative contracts	$ 10.9	0.2	1.7	0.4	8.6
Capital lease obligations	$ 0.2	0.1	0.1	-	-
Capital projects	$ 3.6	3.1	0.5	-	-
Long term service agreements	$ 675.7	27.1	36.4	45.3	566.9
Purchased power	$ 140.6	56.3	84.3	-	-
Gas delivery, service and supply agreements	$ 120.5	25.2	31.8	11.0	52.5
Operating leases	$ 88.4	4.4	7.9	6.5	69.6
Other obligations	$ 23.7	4.2	3.1	0.4	16.0
Total obligations	$ 2,438.8	$ 304.1	$ 339.7	$ 165.3	$ 1,629.7

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

Equity

The shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at December 31, 2012, APUC had 188,763,486 issued and outstanding common shares.

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

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2012, APUC had issued 4,800,000 cumulative rate reset preferred shares, Series A (the "Series A Shares"), yielding 4.5% per cent annually for the initial six-year period ending on December 31, 2018.

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of shares ("Shareholders") of APUC.

As at December 31, 2012, 28.7 million common shares representing approximately 15% of total shares outstanding had been registered with the Reinvestment Plan and during the quarter 325,341 common shares were issued under the Reinvestment Plan. Subsequent to the end of the quarter, on January 15, 2013, an additional 324,051 common shares were issued under the Reinvestment Plan.

On November 9, 2012, APUC issued 4.8 million cumulative rate reset preferred shares, Series A (the "Series A Shares") at a price of $25 per share, for aggregate gross proceeds of $120 million. The shares will yield 4.5% per cent annually for the initial six-year period ending on December 31, 2018. The preferred shares have been assigned a rating of P-3 and Pfd-3(low) by S&P and DBRS respectively. The proceeds of the offering were used primarily to partially fund the acquisition of the Gamesa Wind Facilities interests which closed on December 10, 2012.

On November 19, 2012, APUC announced its intent to redeem, on January 1, 2013, the convertible unsecured debentures maturing on June 30, 2017 ("Series 3 Debentures") bearing interest at 7.0% per annum. During the year ended December 31, 2012, a principal amount of $61.6 million Series 3 Debentures were converted into 14,669,266 shares of APUC. The Series 3 Debentures were convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share. On December 31, 2012, there was a face value of $0.96 million Series 3 Debentures outstanding. Subsequent to the end of the quarter, on January 1, 2013, APUC redeemed the outstanding Series 3 Debentures and issued 150,816 shares as a result of the redemption. Following the redemption, there were no Series 3 Debentures outstanding.

Emera subscription receipts

For the year ended December 31, 2012, APUC issued a total of 26.4 million common shares for proceeds of $142.6 million pursuant to the exercise of subscription receipts issued to Emera in contemplation of certain previously announced transactions, as outlined below:

- On May 14, 2012, in connection with the acquisition of Granite State Electric Utility and EnergyNorth Gas Utility, APUC issued 12.0 million common shares at a price of $5.00 per share to Emera pursuant to a subscription receipt agreement. The $60.0 million cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisitions.
- On June 29, 2012, in connection with the acquisition of Sandy Ridge Wind Facility, APUC received $15.0 million relating to 2.6 million subscription receipts representing a price of $5.74 per share and issued the common shares related to these subscription receipts on July 13, 2012.
- On July 31, 2012, in connection with the acquisition of the Midwest Gas Utilities, APUC issued 7.0 million common shares at a price of $6.45 per share to Emera pursuant to a subscription receipt agreement. The $45.0 million cash proceeds of the subscription receipts were used to fund a portion of the cost of the Midwest Gas Utilities acquisition.
- On December 21, 2012, in connection with the acquisition of Emera's noncontrolling interest in Calpeco, APUC received $38.7 million from Emera related to the issuance of 8.2 million subscription receipts at a price of $4.72 per subscription receipt pursuant to a subscription receipt agreement. On December 27, 2012, APUC issued 4.8 million common shares at a price of $4.72 for share proceeds of $22.6 million. Subsequent to year end, on February 14, 2013, APUC issued 3.4 million common shares at a price of $4.72 for share proceeds of $16.1 million.

Subsequent to the end of the year, in connection with the closing of the acquisition of the Minonk and Senate Wind Facilities from Gamesa USA, that occurred on December 10, 2012, APUC issued 2.6 million common shares at a price of $5.74 on February 7, 2013, and 5.2 million common shares at a price of $5.74 on February 14, 2013. The total $45 million in cash proceeds from the exercise of the subscription receipts were used at the time of the acquisition closing to fund a portion of the cost of the acquisition.

On February 22, 2013, in connection with the acquisition of the Georgia Utility, APUC issued 4.0 million subscription receipts at a price of $7.40 per share to Emera for total proceeds of approximately $29 million.

As at March 14, 2013, in total Emera now owns 46.2 million APUC common shares representing approximately 23.02% of the total outstanding common shares of the Company. APUC believes issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

SHARE BASED COMPENSATION PLANS

For the three and twelve months ended December 31, 2012, APUC recorded $570 and $1,833 (2011 - $287 and $732) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2012, total unrecognized compensation costs related to non-vested options and share unit awards were $1,724 and $219 respectively, and are expected to be recognized over a period of 1.67 years and 1.80 years respectively.

STOCK OPTION PLAN

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

For the year ended December 31, 2012, 1,263,622 options were granted to senior executives and certain senior management of APUC which allow for the purchase of common shares at a weighted average price of $6.24. One third of the options will vest on each of January 1, 2013, 2014, and 2015.

As at December 31, 2012, APUC had 3,750,727 options issued and outstanding. APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date.

PERFORMANCE SHARE UNITS

In October 2011, APUC issued 21,123 performance share units ("PSUs") to certain members of management other than senior executives as part of APUC's long-term incentive program. The PSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these PSUs are accounted for as equity awards.

DIRECTORS DEFERRED SHARE UNITS

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

As at December 31, 2012, 50,172 DSUs had been granted.

EMPLOYEE SHARE PURCHASE PLAN

APUC has an employee share purchase plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. As at December 31, 2012, a total of 61,403 shares had been issued under the ESPP.

MANAGEMENT OF CAPITAL STRUCTURE

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

APUC's objectives when managing capital are:

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

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

RELATED PARTY TRANSACTIONS

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

Transactions with APMI and Senior Executives

- APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the year ended December 31, 2012 were $333 (2011 - $327).

- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. During the year ended December 31, 2012, APUC incurred costs in connection with the use of the aircraft of $598 (2011 - $453) and amortization expense related to the advance against expense reimbursements of $279 (2011 - $274). At December 31, 2012, the remaining amount of the advance was $nil (December 31, 2011 - $279).

- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon LP, a subsidiary of APUC and the legal owner of the St. Leon facility. The related holders of the Class B units received cash distributions of $292 for the year ended December 31, 2012 (2011 - $314). Subsequent to year-end, on January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the Class B units (see note 13 and 14 (b) of the consolidated financial statements).
- APUC provided supervisory management services on a cost recovery basis to a hydroelectric generating facility not owned by APUC where Senior Executives hold an equity interest.
- Rattle Brook is a hydroelectric generating facility in which APUC owns a 45% interest and Senior Executives hold an equity interest in. Rattle Brook is operated on a cost recovery basis by an entity which is partially owned by Senior Executives.
- APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. In 2011, APUC acquired APMI's interest in this royalty for an amount of $600.
- As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee. An amount of U.S. $550 has been accrued as an estimate of the final fee owed to APMI.
- During 2007, APUC allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee of $1,800. As part of its role in the process, APUC has agreed to pay APMI a fee of U.S. $100 which has been accrued as an estimate of the final fee owed to APMI.
- As at December 31, 2012, included in amounts due from related parties is $816 (2011 - $663) owed to APUC from APMI and included in amounts due to related parties is $1,811 (2011 - $1,795) owed to APMI. These amounts arise from the transactions described above.
- Long Sault is a hydroelectric generating facility in which APUC acquired its interest by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the after tax equity cash flows commencing in 2014.
- In March, 2012, APUC and APMI's Senior Executives (the "Parties") reached a term sheet agreement to resolve a number of the historic joint business associations between the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the first quarter of 2013.
- Under the term sheet, it is proposed that APUC will exchange its 45% interest in the 4MW Rattlebrook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement also settles outstanding fees owing to APMI.

Transactions with Emera

- In 2011, a subsidiary of Emera provided lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During the year ended December 31, 2012 APUC paid U.S. $nil (2011 – U.S. $260) in relation to this contract. In 2011, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.
- For the year ended December 31, 2012, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $6,096 (2011 – U.S. $6,564). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.
- As of December 31, 2012, included in amounts due from related parties is $nil (2011 - $1,612) owed from Emera related to the unpaid contribution of their share of Calpeco Electric Utility costs.

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

Business Associations with APMI and Senior Executives

There have been a number of business relationships between Ian Robertson and Chris Jarratt ("Senior Executives"), APMI and related affiliates (collectively the "Parties") and APUC. These relationships include joint ownership of certain generating facility assets, business relationships between the parties and payment of fees associated with previous transactions. In 2011, the Board initiated a process to review all of the remaining business associations with the Parties in order to reduce, streamline and simplify these relationships. The Board formed a special committee and engaged independent consultants to assist with this process.

The co-owned assets and remaining business associations as at December 31, 2012 are listed below. During the quarter ended March 31, 2012, APUC and the Parties reached an agreement to resolve a number of the business associations and relationships (the "Agreement"). The transaction is subject to finalization of definitive agreements which are expected to be completed in the first quarter of 2013. A more detailed description of the Agreement has been set out below in S*ettlement of Other Business Associations*.

i) Rattlebrook hydroelectric generating facility

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

ii) St. Leon wind power generating facility

St. Leon is a 104 MW wind power generating facility which was structured as a limited partnership and has issued Class B units to external parties and Senior Executives. APUC and the Class B unit holders completed a transaction effective January 1, 2013 whereby the Class B units were exchanged for Class C preferred shares of APUC. The characteristics of the Class C preferred shares will provide approximately the same after tax cash to individuals holding such shares as what was estimated to have been expected from the Class B units. The external parties and Senior Executives who formerly held the Class B units are no longer partners in the St Leon limited partnership. The special committee of the Board retained the services of an independent advisor to review the historic financial performance of the St Leon facility, provide a valuation of the Class B units, provide estimation of distributions to Class B unit holders, and to provide advice to APUC in respect thereof.

iii) Brampton Cogeneration Inc.

BCI is an energy supply facility which sells steam produced from APCo's EFW facility. APMI maintains a carried interest equal to 50% of the annual returns on the project greater than 15%. No amounts have ever been paid under this carried interest. In 2008, APMI earned a construction supervision fee of $100 in relation to the development of this project which has been accrued. This relationship was addressed pursuant to the Agreement.

iv) Long Sault Rapids hydroelectric generating facility

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

v) Chartered aircraft

APUC utilizes chartered aircraft owned by an affiliate of APMI. At December 31, 2012, the remaining amount of the advance was $nil (December 31, 2011 - $279).

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 on December 31, 2015.

vii) Operations services

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

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. An amount of U.S. $0.6 million has been accrued as an estimate of the final fee owed to APMI. This was settled pursuant to the Agreement.

ix) Clean Power Income Fund

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund ("Clean Power") to expire and earned a termination fee of $1.8 million. As part of its role in the process, APUC has agreed to pay APMI a fee of $0.1 million. As of December 31, 2011 this amount is accrued and included in accounts payable on the consolidated balance sheet. This was settled pursuant to the Agreement.

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. This relationship was settled pursuant to the Agreement.

xi) Trafalgar

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

Settlement of Other Business Associations

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

Under the Agreement, APUC will exchange its 45% interest in the 4MW Rattlebrook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement also terminates outstanding fees potentially owing to APMI in respect of the following: the historic transactions including the Sanger repowering project, the offer to acquire Clean Power Income Fund and the development of the Red Lily I wind project.

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

TREASURY RISK MANAGEMENT

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

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

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 59% of EBITDA in 2012 and 75% 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 a net impact on U.S. operations of approximately $6.3 million ($0.04 per share) on an annual basis.

APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes.

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.

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

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

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

The December 10, 2012 acquisition of Senate Wind Facility included a physical hedge which commences on January 1, 2013 for a 15 year period. The physical hedge is structured to hedge 64% of Senate Wind Facility's production volume against exposure to ERCOT North Zone current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $1.1 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge which commences on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's production volume against exposure to PJM Northern Illinois Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in market prices would result in a change in revenue of about $1.1 million for the year.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract which commences on January 1, 2013 for a 20 year period. The power sales contract is structured to provide pricing certainty for approximately 85% of the Shady Oaks Wind Facility's production volume against exposure to PJM

ComEd Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in market prices would result in a change in revenue of about $0.5 million for the year.

Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its trade receivables, derivative financial instruments and short term investments. APUC has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

APUC does not believe this risk to be significant as approximately 82% of APCo Renewable Energy division's revenue, approximately 78% of APCo Thermal Energy division's revenue, and over 80% of APCo's total revenue is earned from large utility customers having a credit rating of BBB- or better.

The following chart sets out APCo's significant customers, their credit ratings and percentage of total revenue associated with the customer:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Manitoba Hydro	AA	26.2	28%
Hydro – Quebec	A+	20.8	23%
Ontario Electricity Financial Corporation	Aa2	10.0	11%
Maine Public Service**	BBB+	8.8	10%
ISO New England		3.8	4%
TransAlta Corp – Dickson Dam	BBB-	3.8	4%
Public Service Company of New Hampshire	BBB	1.4	2%
Total – Renewable		**$ 74.8**	**82%**
Thermal Energy Division			
Pacific Gas and Electric Company	BBB	12.4	39%
Connecticut Light and Power	A-	12.3	39%
Total – Thermal		**$ 24.7**	**78%**
Total – APCo		**$ 99.5**	**80%**

* Ratings by Moody's or Standard & Poor's as of February 2013.
** Maine Public Service is a subsidiary of Emera.

The remaining revenue is primarily earned by Liberty Utilities. In this regard, the credit risk related to Liberty Utilities (West) and Liberty Utilities (Central)'s accounts receivable balances related to the water and wastewater utilities total U.S. $6.3 million which is spread over approximately 77,000 connections, resulting in an average outstanding balance of approximately $80.00 per connection. Liberty Utilities (East) and Liberty Utilities (Central)'s accounts receivable balances related to the natural gas utilities total U.S. $33.8 million, while the Liberty Utilities (East) and Liberty Utilities (West)'s accounts receivable balances related to the electric utilities total U.S. $21.1 million. The natural gas and electrical utilities derive over 80% of their revenue from residential customers.

In addition to the counterparty risk related to customer sales outlined above, APCo and Liberty Utilities utilizes derivative instruments as hedges of certain financial risks as discussed elsewhere in this MD&A. APUC is exposed to credit risk related to counterparties to the extent those derivative instruments are in an asset position at a point in time. We manage our counterparty risk by entering into these instruments with counterparties having a credit rating of BBB- or better.

Interest rate risk

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to interest rate risk. Borrowings subject to variable interest rates are as follows:

- APUC's operating credit facility is subject to a variable interest rate. The APUC Facility has no amounts outstanding as at December 31, 2012. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The APCo Facility had $27.1 million outstanding as at December 31, 2012. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.3 million annually.
- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2012. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.

- The Liberty Facility had $27.4 million outstanding as at December 31, 2012. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.3 million annually.

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

Liquidity risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due.

Both APCo and Liberty have established financing platforms to access new liquidity from the capital markets as requirements arise. APUC continually monitors the maturity profile of its debt and adjusts accordingly to ensure sufficient liquidity exists at each of APCo and Liberty Utilities to meet their liabilities when due.

As at December 31, 2012, APUC and its subsidiaries had a combined $224.3 million of committed and available credit facilities remaining and $53.1 million of cash resulting in $277.4 million of total liquidity and capital reserves.

APUC currently pays a dividend of $0.31 per common share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements and to fund working capital that, in its judgment, ensures APUC's long-term success. Based on the level of dividends paid during the year ended December 31, 2012, cash provided by operating activities exceeded dividends declared by 1.8 times and exceeds Adjusted Cash From Operations by 2.1 times.

The long term portion of debt totals approximately $770.9 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facilities and project debt with borrowings having less favorable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted.

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

Commodity price risk

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty 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 net revenue by approximately $0.2 million on an annual basis.
- APCo's Windsor Locks facility's ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to Ahlstrom. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 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 net revenue by approximately $0.1 million.
- AES provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 250,000 MW-hrs in fiscal 2013. While the Tinker facility is expected to provide a significant portion of the energy required to service these customers, AES 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 AES 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 $2.5 million on an annualized basis. This risk is mitigated through the use of short-term financial energy hedge contracts. AES has committed to acquire approximately 72,000 MW-hrs of net energy over the next 12 months at an average rate of

approximately U.S. $52 per MW-hr. The mark-to-market value of these forward energy purchase contracts at December 31, 2012 was a net liability of U.S. $0.3 million.

Liberty Utilities is exposed to energy price risk in its Liberty Utilities (West) region which is mitigated through certain regulatory constructs. Liberty Utilities (West) provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the CPUC. The utility purchases the energy, capacity, and related service requirements for its customers from NV Energy via a purchase power agreement at rates reflecting NV Energy's system average costs.

The rate structure in California allows for a pass-through of energy costs to rate payers on a dollar for dollar basis, through the energy cost adjustment clause ("ECAC") mechanism, which is designed to recoup power supply costs that are caused by the fluctuations in the price of fuel and purchased power. Actual power supply costs incurred by the facility are tracked and compared to the base rate power supply costs to ensure the cumulative variance, including carrying charges, does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows for an adjustment to the Calpeco Electric Utility's approved rates (including carrying charges associated therewith), substantially eliminating the commodity risk associated with the purchase of power. In the 2012 California Utility's general rate case, a revenue decoupling mechanism and a vegetation management memorandum account were agreed upon. The revenue decoupling mechanism will decouple base revenues from fluctuations caused by weather and economic factors reducing volumetric risk for the utility. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses, one of the largest expenses of the utility, reducing the potential for expenses to exceed the amounts allowed for in general rates.

In the Liberty Utilities (East) region, Granite is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, GSEC provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for residential and small use customers and quarterly for large customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of GSEC's Default Service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by GSEC which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC each quarter. GSEC is only committed to the winning Default Service supplier(s) after approval by the NH PUC so that there is no risk of commodity commitment without pass-through rate recovery.

In the Liberty Utilities (East) region, EnergyNorth Gas Utility purchases pipeline capacity, storage and commodity from a variety of counterparties. EnergyNorth Gas Utility's portfolio of assets, planning and forecasting methodology is approved by the NHPUC bi-annually through an Integrated Resource Plan filing. In addition, EnergyNorth Gas Utility files with the NHPUC for recovery of its transportation and commodity costs through a semi-annual winter and summer Cost of Gas (COG) filing and approval process. EnergyNorth Gas Utility establishes rates for its customers within the COG filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, EnergyNorth Gas Utility has implemented a NHPUC approved commodity hedging program designed to hedge approximately 60% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be pass-through to customers through the COG filing and the approved rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, EnergyNorth Gas Utility has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with carrying costs to the next year's period COG filing, i.e. winter to winter and summer to summer.

Liberty Utilities (Central) region purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual State Commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. Liberty Utilities (Central) establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, Liberty Utilities (Central) has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Liberty Utilities (Central) may adjust its rates on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs.

OPERATIONAL RISK MANAGEMENT

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

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

Mechanical and Operational Risks

APUC is entirely dependent upon the operations and assets of APUC's businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards.

The water distribution networks of Liberty Utilities operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

The electricity distribution systems owned by Liberty Utilities are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

The gas distribution systems owned by Liberty Utilities are subject to significant risks which may lead to fire and/or explosion which may have serious impact on life and property. Risks include third party damage, significant leaks, type/age of pipelines and severe weather events.

These risks are mitigated through the diversification of APUC's operations, both operationally (APCo and Liberty Utilities) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses.

Regulatory Risk

Profitability of APUC businesses is in part dependant on regulatory climates in the jurisdictions in which it operates. In the case of some APCo hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue.

Liberty Utilities' facilities are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies 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 electricity and natural gas distribution utilities. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Electricity and natural gas distribution utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities, and while Liberty Utilities believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Liberty Utilities regularly works with its governing authorities to manage the affairs of the business.

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.

Liberty Utilities' facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Utilities has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging distribution facilities and expenses associated with providing new sources of commodity supply can generally be included in the facility's rate base and thus Liberty Utilities expects to be allowed to earn a return on such investment.

In conjunction with the recent acquisitions the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements to: (i) remove of wind farm facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants) and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas main when removed from the pipeline system, (iii) clean and remove storage tanks containing waste oil and other waste contaminants, and (iv) remove asbestos upon major renovation or demolition of structures and facilities.

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.

Liberty Utilities faces environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of an electrical distribution system are related to potential accidental release of mineral oil to the environment from non-operational events and the management of hazardous and universal waste in accordance with the various Federal, State and local environmental laws. Like most other industrial companies, Liberty Utilities generates some hazardous wastes as a result of its operations. Under Federal and State Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, Liberty Utilities investigates promptly all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation.

The primary risks associated with the operation of gas distribution systems are related to uncontrolled natural gas releases, equipment damage by construction equipment/third parties or severe weather events. The gas distribution assets are heavily regulated by the Pipeline Hazardous Material Safety Administration (PHMSA) under the United States Department of Transportation and their respective State regulations in which the assets are located. Gas Distribution systems are subject to detailed annual inspections by State Regulatory Agency to ensure strict adherence to applicable regulations. PHMSA reviews the Company's policies in reference to operation and maintenance, construction, training, emergency response, reporting, contractor management and measurements. Liberty monitors all aspects of pipeline safety and quickly mitigates any identified concerns.

Liberty Utilities (East)'s ongoing operations and historic activities are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the United States Environmental Protection Agency and the New Hampshire Department of Environmental Services ("NHDES"). Similar to other industrial companies, the gas and electric distribution utilities generate certain hazardous wastes. Under federal and state Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of regulated utilities these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

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

Liberty Utilities estimates the remaining cost of these MGP-related environmental cleanup activities will be $68,180 which at a discount rate of 3.5% represents $56,587 at December 31, 2012, which has been accrued as Liberty Utilities' estimate of costs for known issues. By rate orders, the Regulator provided for the recovery of site investigation and remediation costs and accordingly, at December 31, 2012 the Company has reflected a regulatory asset of $55,721 for the remediation of the MGP and related sites.

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 December 31, 2012.

Cycles and Seasonality

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized.

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

Liberty Utilities (West) and Liberty Utilities (Central)'s demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

Liberty Utilities (West) region's demand for energy is primarily affected by weather conditions and conservation initiatives. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. Liberty Utilities (West) provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts to revenues.

Prior to January 1, 2013, Liberty Utilities (West) was exposed to volume sales risk related to seasonal weather variations. Effective on January 1, 2013, pursuant to a CPUC approved Rate Case decision, a Base Revenue Requirement Balancing Account (BRAAM) rate mechanism has been implemented. The BRAAM removes the seasonal variations of the revenues and flattens the net revenue (minus Fuel, Purchased Power, ECAC) to a monthly rate of $3.0 million or $35.5 million annually. This substantially eliminates the risk of revenue variations associated with seasonal weather changes.

Liberty Utilities (East) and Liberty Utilities (Central) natural gas demand is driven by the seasonal heating requirements of its residential, commercial, and industrial customer. That is, the colder the weather the greater the demand for natural gas to heat homes and businesses. As such, Liberty Utilities (East) and Liberty Utilities (Central)'s natural gas demand profiles typically crests in the winter months of January and February and declines in the summer months of July and August.

Litigation risks and other contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

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

With respect to the civil proceedings, the Second Circuit Court of Appeal dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. On April 3, 2012, the District Court granted APUC summary judgment on its counter-claims against Trafalgar. The District Court found that Trafalgar was in default of the indenture and the loan agreements and that APUC was entitled to proceed to enforce its rights against its collateral. Trafalgar has filed a notice of appeal of the Memorandum-Decision and Order. Algonquin filed its brief on October 19, 2012 with a hearing dated anticipated in the first quarter of 2013. The bankruptcy proceedings are continuing with a Second Circuit Court of Appeal hearing scheduled for December 12, 2012 to hear the appeal of the District Court's October 25, 2011 decision holding that Algonquin does not have a security interest in the monies transferred by Trafalgar before it filed for bankruptcy protection.

With respect to the bankruptcy proceedings, on January 30, 2013, the U.S Second Circuit Court of Appeals held that APCo did have a security interest in Trafalgar's engineering malpractice claim and its proceeds. On February 20, 2013, Trafalgar filed a petition for a rehearing with the U.S, Second Circuit Court of Appeals.

On October 21, 2011 the Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5.4 million (including interest) to the government of Québec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years. The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. The potential unrecoverable loss, if any, for the related prior periods could be up to $5.8 million. The parties are attempting to resolve this matter through good faith negotiations.

Obligations to serve

Liberty Utilities may have facilities located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, Liberty Utilities may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the eight quarter ended December 31, 2012:

Millions of dollars (except per share amounts)	1st Quarter 2012	2nd Quarter 2012	3rd Quarter 2012	4th Quarter 2012
Revenue	$ 63.3	$ 64.6	$ 98.7	$ 143.1
Adjusted EBITDA	23.0	25.1	24.8	33.4
Net earnings / (loss) attributable to shareholders from continuing operations	2.5	6.3	0.04	6.6
Net earnings / (loss) attributable to shareholders	2.3	6.1	(0.2)	6.4
Net earnings / (loss) per share from continuing operations	0.02	0.04	0.00	0.04
Net earnings / (loss) per share	0.02	0.04	0.00	0.04
Adjusted net earnings	4.3	7.1	3.9	5.4
Adjust net earnings per share	0.03	0.05	0.02	0.03
Total Assets	1,265.6	1,416.0	1,967.1	2,778.2
Long term debt*	403.7	473.8	705.1	771.8
Dividend declared per common share	0.07	0.07	0.08	0.08

	1st Quarter 2011	2nd Quarter 2011	3rd Quarter 2011	4th Quarter 2011
Revenue	$ 70.1	$ 64.9	$ 65.1	$ 70.5
Adjusted EBITDA	26.7	27.9	25.8	24.3
Net earnings / (loss) attributable to shareholders from continuing operations	4.8	7.0	19.6	(7.7)
Net earnings/(loss) attributable to shareholders	5.0	7.3	19.6	(8.5)
Net earnings / (loss) per share from continuing operations	0.05	0.06	0.16	(0.6)
Net earnings/(loss) per share	0.05	0.06	0.16	(0.07)
Adjusted net earnings	5.1	7.9	22.4	3.6
Adjust net earnings per share	0.05	0.07	0.19	0.03
Total Assets	1,175.8	1,177.7	1,263.1	1,282.6
Long term debt*	507.0	451.1	472.2	455.0
Dividend declared per common share	0.07	0.07	0.07	0.07

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

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

Quarterly revenues have fluctuated between $63.3 million and $143.1 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between net earnings attributable to shareholders of $19.6 million and a net loss of $8.5 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

Disclosure Controls

At the end of the fiscal year ended December 31, 2012, APUC carried out an evaluation, under the supervision of and with the participation of APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2012, APUC's disclosure controls and procedures are effective.

Internal controls over financial reporting

APUC's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of APUC; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of APUC are being made only in accordance with authorizations of management and directors of APUC; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of APUC's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

During the year ended December 31, 2012, APUC acquired EnergyNorth Gas Utility, Granite State Electric Utility, the Midwest Gas Utilities, and the Sandy Ridge, Minonk and Senate Wind Facilities. The financial information for these business acquisitions is included in this MD&A and in Note 3 to the consolidated financial statements. As permitted by National Instrument 52-109 and the U.S. Securities and Exchange Commission, the Company excluded these acquisitions from its evaluation of the effectiveness of APUC's internal controls over financial reporting as of December 31, 2012 due to the complexity associated with assessing internal controls during integration efforts and the proximity of some of the acquisitions to year-end.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2012 based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2012.

During the year ended December 31, 2012, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. APUC continues to implement its internal control structure over the operations of the acquired businesses discussed above.

Critical Accounting Estimates and Polices

The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, recoverability of deferred tax assets, rate-regulation, unbilled revenue, pension and postretirement benefits, and fair value of derivatives. Actual results may differ from these estimates.

APUC's significant accounting policies are discussed in Note 1 to the consolidated financial statements. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

Estimated useful lives and recoverability of Long-Lived Assets and Intangibles

The provisions for depreciation of utility property and equipment for financial reporting purposes are made on the straight-line method based on the estimated service lives of the assets. Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process. Non-regulated property and equipment are depreciated on a straight-line basis over useful lives of the related assets. Management believes the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries could result in a reduction of the estimated useful lives of those non-regulated assets or in an impairment write-down of the carrying value of these properties.

The carrying value of long-lived assets, including identifiable intangibles, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable. Some of the factors APUC considers as indicators of impairment include whether a facility is operating, its plan for return to service, external influences such as natural disasters, energy pricing and profitability and changes in regulation. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, interest rates, regulatory matters and operating costs could negatively affect the fair value of APUC's assets and result in an impairment charge.

Valuation of Deferred Tax Assets

Income taxes are accounted for using the asset and liability method. Under this method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Although management believes the assumptions, judgments and estimates are reasonable, changes in tax laws and changes in operations could significantly impact the amounts provided for income taxes in our financial statements.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to Liberty Utilities' operations. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or write down.

Unbilled Energy Revenues

Revenues related to natural gas, electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of natural gas, energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Derivatives

APUC uses derivative instruments to manage exposure to changes in commodity prices, foreign exchange rates and interest rates. Derivative instruments that do not meet the normal purchases and sales exception are recorded at fair value. Changes in the derivative's fair value are recognized as regulatory assets or liabilities when the regulator permits recovery of the hedging strategy. For derivative designated in a cash flow hedge relationship, the effective portion of the change in fair value is deferred to accumulated other comprehensive income, until the hedged transaction occurs and is recognized in earnings. The ineffective portion is immediately recognized in earnings. For derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations, foreign currency transaction gain or loss that are effective as an economic hedge of the net investment in a foreign operation are reported in other comprehensive income.

Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets adjusted for nonperformance risk. A significant change in estimate could affect APUC's results of operations.

Pension and Postretirement Benefits

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and post-retirement benefit plans for qualifying employees in the related acquired businesses. The obligations and related costs are calculated using actuarial concepts, which include critical assumptions related to the discount rate, expected rate of return on plan assets and medical cost trend rates. These assumptions are important elements of expense and/or liability measurement and are updated on an annual basis, or upon the occurrence of significant events. A significant change in estimate could affect APUC's results of operations. In addition, the determination of the fair value of pension and postretirement benefits assets and liabilities acquired in the business acquisitions has been based upon management's preliminary estimates and assumptions. The Company will continue to review information and perform further analysis. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts noted.

Additional disclosure of APUC's critical accounting estimates is also available SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated balance sheets of Algonquin Power & Utilities Corp. as of December 31, 2012 and December 31, 2011, and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows for the years then ended. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as of December 31, 2012 and December 31, 2011, and its consolidated results of operations and its consolidated cash flows for the years then ended in conformity with US generally accepted accounting principles

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 14, 2013 expressed an unqualified (unmodified) opinion on the effectiveness of Algonquin Power & Utilities Corp.'s internal control over financial reporting.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 14, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Algonquin Power & Utilities Corp.

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Algonquin Power & Utilities Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included under the heading Internal Controls over Financial Reporting in Management's Discussion and Analysis for the year ended December 31, 2012. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

KPMG

In our opinion, Algonquin Power & Utilities Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Algonquin Power & Utilities Corp. acquired Granite State Electric Company, EnergyNorth Natural Gas Inc., Liberty Energy (Midstates) Corp., Wind Portfolio SponsorCo LLC and Wind Portfolio Holdings LLC during 2012, and management excluded from its assessment of the effectiveness of Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2012, Granite State Electric Company, EnergyNorth Natural Gas Inc., Liberty Energy (Midstates) Corp., Wind Portfolio SponsorCo LLC and Wind Portfolio Holdings LLC's internal control over financial reporting associated with total assets of $757.7 million and total revenues of $117.0 million included in the consolidated financial statements of Algonquin Power & Utilities Corp. and subsidiaries as of and for the year ended December 31, 2012. Our audit of internal control over financial reporting of Algonquin Power & Utilities Corp. also excluded an evaluation of the internal control over financial reporting of Granite State Electric Company, EnergyNorth Natural Gas Inc., Liberty Energy (Midstates) Corp., Wind Portfolio SponsorCo LLC and Wind Portfolio Holdings LLC.

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Algonquin Power & Utilities Corp. as of December 31, 2012 and December 31, 2011, and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows for the years ended December 31, 2012 and December 31, 2011, and our report dated March 14, 2013 expressed an unqualified (unmodified) opinion on those consolidated financial statements.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 14, 2013

Algonquin Power & Utilities Corp.

Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 53,122	$ 72,887
Accounts receivable, net of allowance for doubtful accounts of $4,360 and $385 (note 4)	90,361	44,113
Natural gas in storage (note 1(g))	19,279	-
Supplies and consumables inventory	4,233	2,714
Regulatory assets (note 7)	10,644	2,458
Due from related parties (note 19)	816	2,275
Prepaid expenses	10,886	5,620
Notes receivable (note 8)	537	482
Deferred tax asset (note 17)	10,567	13,022
Income tax receivable (note 17)	556	133
Derivative instruments (note 24)	7,020	-
Assets held for sale (note 18)	24,390	25,847
Other current assets (note 12)	833	833
	233,244	170,384
Property, plant and equipment (note 5)	2,162,715	920,109
Intangible assets (note 6)	56,781	55,269
Goodwill	61,459	9,710
Regulatory assets (note 7)	123,748	2,571
Derivative instruments (note 24)	6,230	-
Long-term investments and notes receivable (note 8)	37,646	39,820
Deferred non-current income tax asset (note 17)	77,497	67,671
Other assets (note 12)	18,917	16,773
	$ 2,778,237	$ 1,282,307

Algonquin Power & Utilities Corp.

Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2012	December 31, 2011
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 34,283	$ 8,382
Accrued liabilities	99,468	46,821
Due to related parties (note 19)	1,811	1,795
Dividends payable (note 16)	15,498	9,566
Regulatory liabilities (note 7)	6,065	2,469
Long term liabilities (note 9)	1,768	1,624
Other long term liabilities (note 13)	4,352	1,037
Advances in aid of construction (note 1(o))	591	604
Derivative instruments (note 24)	2,211	2,935
Income tax liability (note 17)	539	407
Deferred credits (note 17)	5,754	6,314
Deferred income tax liability (note 17)	1,133	723
	173,473	82,677
Long-term liabilities (note 9)	769,058	331,092
Convertible debentures (note 10)	960	122,297
Advances in aid of construction (note 1(o))	71,626	74,547
Regulatory liabilities (note 7)	82,050	19,184
Deferred income tax liability (note 17)	100,798	53,231
Derivative instruments (note 24)	15,605	5,209
Deferred credits (note 17)	25,816	30,348
Pension and post employment benefits (note 11)	59,246	-
Environmental obligation (note 21)	56,587	-
Other long-term liabilities (note 13)	20,889	11,027
	1,202,635	646,935
Equity:		
Preferred shares (note 14(b))	116,546	-
Common shares (note 14(a))	1,245,326	975,263
Subscription receipts (note 14(a)(iii))	61,160	-
Additional paid-in capital (note 14)	5,224	1,525
Deficit	(406,143)	(366,080)
Accumulated other comprehensive loss (note 15)	(104,867)	(96,510)
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	917,246	514,198
Non-controlling interests	484,883	38,497
Total Equity	1,402,129	552,695
Commitments and contingencies (note 21)		
Subsequent events (notes 3,10, 14, 18 and 25)		
	$ 2,778,237	$ 1,282,307

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)

		2012		2011
Revenue:				
Regulated electricity sales and distribution	$	108,457	$	77,368
Regulated gas sales and distributions		75,718		-
Regulated water reclamation and distribution		46,423		44,989
Non-regulated energy sales		121,150		128,311
Waste disposal fees		14,288		16,406
Other revenue		3,851		3,643
		369,887		270,717
Expenses				
Operating		130,333		84,018
Regulated electricity purchased		68,209		46,508
Regulated gas purchased		37,461		-
Non-regulated fuel for generation		14,589		24,628
Depreciation of property, plant and equipment		50,382		37,988
Amortization of intangible assets		4,151		6,433
Administrative expenses		19,608		17,534
Write down of long-lived assets		-		15,166
Gain on foreign exchange		(561)		(652)
		324,172		231,623
Operating income from continuing operations		45,715		39,094
Interest expense		35,941		30,437
Interest, dividend income and other income		(7,239)		(5,659)
Acquisition-related costs		7,709		2,965
Loss/(gain) on derivative financial instruments (note 24(b))		(233)		5,844
		36,178		33,587
Earnings from continuing operations before income taxes		9,537		5,507
Income tax expense (recovery) (note 17)				
Current		738		300
Deferred		(14,304)		(22,847)
		(13,566)		(22,547)
Earnings from continuing operations		23,103		28,054
Loss from discontinued operations net of tax (note 18)		(1,157)		(752)
Net earnings		21,946		27,302
Net earnings attributable to non-controlling interests		7,414		3,921
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$	14,532	$	23,381
Basic net earnings per share from continuing operations (note 20)	$	0.10	$	0.21
Basic net loss per share from discontinued operations (note 20)		(0.01)		(0.01)
Basic net earnings per share (note 20)		0.09		0.20
Diluted net earnings per share from continuing operations (note 20)		0.10		0.21
Diluted net loss per share from discontinued operations (note 20)		(0.01)		(0.01)
Diluted net earnings per share (note 20)	$	0.09	$	0.20

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.

Consolidated Statements of Comprehensive Income (Loss)

(thousands of Canadian dollars)

		2012		2011
Net earnings	$	21,946	$	27,302
Other comprehensive income (loss):				
Foreign currency translation adjustment, net of tax of $560 and ($Nil), respectively (notes 1(v), 9 and 24(c))		(7,829)		4,272
Change in fair value of cash flow hedge, net of tax of $1,715 and $Nil, respectively (note 24(b) and (ii))		3,593		-
Change in unrealized pension and other post-retirement expense, net of tax of $1,653 and $Nil, respectively (note 11)		(2,453)		(48)
Other comprehensive income (loss), net of tax		(6,689)		4,224
Comprehensive income		15,257		31,526
Comprehensive income attributable to the non-controlling interest		9,083		4,810
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$	6,174	$	26,716

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.

Consolidated Statement of Equity

(thousands of Canadian dollars)

For the year ended December 31, 2012:

	Common Shares	Preferred Shares	Subscription Receipts	Additional paid-in capital	Accumulated Deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2011	$ 975,263	$	$	$ 1,525	$ (366,080)	$ (96,510)	$ 38,497	$ 552,695
Net earnings					14,532		7,414	21,946
Other comprehensive loss	-	-	-	-	-	(8,357)	1,668	(6,689)
Dividends declared and distributions to non-controlling interests	-	-	-	-	(43,619)	-	(2,640)	(46,259)
Dividends and issuance of shares under dividend reinvestment plan	7,343	-	-	-	(7,343)	-	-	-
Exercise and conversion of subscription receipts	142,609	-	-	-	-	-	-	142,609
Issuance of subscription receipts	-	-	61,160	-	-	-	-	61,160
Conversion and redemption of convertible debentures	118,779	-	-	(689)	-	-	-	118,090
Issuance of common shares under employee share purchase plan	432	-	-	-	-	-	-	432
Stock compensation expense	-	-	-	1,956	-	-	-	1,956
Public offering related taxes	900			-	-	-	-	900
Issuance of preferred shares	-	116,546	-	-	-	-	-	116,546
Acquisition of 49.99% of Liberty Energy (California)	-	-	-	-	(3,633)		(35,023)	(38,656)
Acquisition of U.S. Wind farms	-	-	-	2,432	-	-	474,967	477,399
Balance, December 31, 2012	$ 1,245,326	$ 116,546	$ 61,160	$ 5,224	$ (406,143)	$ (104,867)	$ 484,883	$ 1,402,129

For the year ended December 31, 2011:

	Common Shares	Preferred Shares	Subscription Receipts	Additional paid-in capital	Accumulated Deficit	Accumulated OCI (CTA)	Non-controlling interests	Total
Balance, December 31, 2010	$ 795,329	$ -	$ -	$ 1,612	$ (357,035)	$ (99,845)	$ -	$ 340,061
Net earnings					23,381		3,921	27,302
Other comprehensive income	-	-	-	-	-	3,335	889	4,224
Dividends declared and distributions to non-controlling interests	-	-	-	-	(32,426)	-	(523)	(32,949)
Conversion and redemption of convertible debentures	59,973	-	-	(815)	-	-	-	59,158
Public offering	91,188	-	-	-	-	-	-	91,188
Exercise and conversion of subscription receipts	27,700	-	-	-	-	-	-	27,700
Stock compensation expense	-	-	-	728	-	-	-	728
Acquisition of Liberty Energy (California)	-	-	-	-	-	-	34,210	34,210
Amounts received in connection with Highground transaction	1,073	-	-	-	-	-	-	1,073
Balance, December 31, 2011	$ 975,263	$ -	$ -	$ 1,525	$ (366,080)	$ (96,510)	$ 38,497	$ 552,695

See accompanying notes to interim consolidated financial statements

Algonquin Power & Utilities Corp.

Consolidated Statements of Cash Flows

(thousands of Canadian dollars)

		2012		2011
Cash provided by (used in):				
Operating Activities:				
Net earnings from continuing operations	$	23,103	$	28,054
Adjustments and items not affecting cash:				
Depreciation of property, plant and equipment		50,382		37,988
Amortization of intangible assets		4,151		6,433
Other amortization		2,175		2,192
Gain on sale of assets		-		(357)
Deferred taxes		(14,304)		(22,847)
Unrealized (gain)/loss on derivative financial instruments		(3,127)		2,324
Share-based compensation		1,956		769
Pension and post retirement expense		2,852		-
Write down of long lived assets		-		15,166
Unrealized foreign exchange loss		57		-
Changes in non-cash operating items (note 22)		(3,884)		(1,542)
Cash provided/(used) in discontinued operations (note 18)		(375)		1,515
		62,986		69,695
Financing Activities:				
Cash dividends on common shares		(36,917)		(28,582)
Cash dividends on preferred shares		(769)		-
Cash distributions to non-controlling interests		(2,640)		(523)
Issuance of common shares		143,041		118,846
Proceeds from subscription receipts		61,160		-
Issuance of preferred shares		115,300		-
Deferred financing costs		(5,435)		(3,642)
Increase in long-term liabilities		505,542		204,759
Decrease in long-term liabilities		(75,432)		(134,932)
Increase in advances in aid of construction		1,051		6,288
Decrease in other long-term liabilities		(860)		(297)
		704,041		161,917
Investing Activities:				
Decrease/(increase) in restricted cash		805		(1,036)
Increase in short-term investments		-		(833)
Increase in other assets		(2,481)		(2,438)
Distributions received in excess of equity income		343		3,839
Receipt of principal on notes receivable		1,894		1,172
Decrease in non-controlling interest		-		1,351
Proceeds from liquidation of Highground assets		-		1,073
Increase in long-term investments and notes receivable		-		(6,900)
Proceeds from sale of property, plant and equipment		-		1,583
Proceeds from sale of subsidiaries		204		-
Additions to property, plant and equipment		(75,692)		(60,745)
Additions to intangibles (note 3(f))		(2,237)		-
Acquisitions of operating entities (note 3(a),(b), and (d))		(669,905)		(100,058)
Acquisition of noncontrolling interest in Calpeco (note 3(e))		(38,756)		-
		(785,825)		(162,992)
Effect of exchange rate differences on cash		(967)		(482)
Increase/(decrease) in cash and cash equivalents from continuing operations		(19,765)		68,138
Cash and cash equivalents, beginning of the period		72,887		4,749
Cash and cash equivalents, end of the period	$	53,122	$	72,887
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest expense	$	28,635	$	28,143
Cash paid during the period for income taxes	$	252	$	195
Non-cash transactions				
Property, plant and equipment acquisitions in accruals	$	10,495	$	8,556

See accompanying notes to consolidated financial statements

ALGONQUIN POWER & UTILITIES CORP.

Notes to the Consolidated Financial Statements
December 31, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

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

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

1. Significant accounting policies

(a) Basis of preparation

The accompanying consolidated financial statements and accompanying notes have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosures required under Regulation S-X provided by the Securities and Exchange Commission ("SEC").

(b) Basis of consolidation

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

(c) Accounting for rate regulated operations

The regulated utility operating companies owned by Liberty Utilities are subject to rate regulation generally overseen by the public utility commissions of the states in which they operate (the "Regulator"). The Regulator provides the final determination of the rates charged to customers. APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Included in Note 7, Regulatory Assets & Liabilities are details of regulatory assets and liabilities, and their current regulatory treatment.

In the event the Company determines that its net regulatory assets are not probable of recovery, it would no longer apply the principles of the current accounting guidance for rate regulated enterprises and would be required to record an after-tax, non-cash charge (credit) against income for any remaining regulatory assets (liabilities). The impact could be material to the Company's reported financial condition and results of operations.

The electric utilities' and the water utilities' accounts are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC") and National Association of Regulatory Utility Commissioners, respectively.

(d) Cash and cash equivalents

Cash and cash equivalents include all highly liquid instruments with an original maturity of three months or less.

ALGONQUIN POWER & UTILITIES CORP.

Notes to the Consolidated Financial Statements
December 31, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

1. Significant accounting policies (continued)

(e) Restricted cash

Restricted cash represent reserves and amounts set aside pursuant to requirements of various debt agreements and requirements of ISO New England, Inc. Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(f) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the receivables aging and current payment patterns. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance-sheet credit exposure related to its customers.

(g) Gas in storage

Gas in storage is reflected at weighted average cost or first-in-first-out as required by the regulators and represents natural gas and liquefied natural gas that will be utilized in the ordinary course of business of the gas utilities. Existing rate orders allow the Company to pass through the cost of gas purchased directly to the rate payers along with any applicable authorized delivery surcharge adjustments. Accordingly, the recoverable value of gas in storage does not fall below the cost to the Company (note 7).

(h) Supplies and consumables inventory

Supplies and consumables inventory (other than capital spares and rotatable spares, which are included in property, plant, and equipment) are charged to inventory when purchased and then capitalized to plant or expensed, as appropriate, when installed, used or become obsolete. These items are stated at the lower of cost and replacement cost.

(i) Property, plant and equipment

Property, plant and equipment, consisting of renewable and thermal generation assets, electrical, gas, water and wastewater distribution assets, equipment and land, are recorded at cost. The costs of acquiring or constructing property, plant and equipment include the following: materials, labour, contractor and professional services, construction overhead directly attributable to the capital project (where applicable), interest for non-regulated property and allowance for equity funds used during construction ("AFUDC") for regulated property. Plant and equipment under capital leases are initially recorded at cost determined as the present value of minimum lease payments.

ALGONQUIN POWER & UTILITIES CORP.

Notes to the Consolidated Financial Statements
December 31, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

1. Significant accounting policies (continued)

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ALGONQUIN POWER & UTILITIES CORP.

Notes to the Consolidated Financial Statements
December 31, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

1. Significant accounting policies (continued)

(i) Property, plant and equipment (continued)

Contributions in aid of construction represent amounts contributed by customers and governments and developers for the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction (note 1(o)) but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset as a reduction to depreciation expense.

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of Liberty Utilities are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operation in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment are charged to earnings as incurred.

(j) Intangibles

The fair value of power sales contracts acquired in business combinations are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 25 years from date of acquisition.

Customer relationships acquired in business combinations are amortized on a straight-line basis over their estimated life of 40 years.

(k) Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is not included in the rate-base on which regulated utilities are allowed to earn a return and is not amortized.

The Company annually assesses qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If it is more likely than not that a reporting unit's fair value is less than its carrying amount, the Company calculates the fair value of the reporting unit. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

ALGONQUIN POWER & UTILITIES CORP.

Notes to the Consolidated Financial Statements
December 31, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

1. Significant accounting policies (continued)

(l) Impairment of long-lived assets

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable.

Assets Held and Used: Recoverability of assets expected to be held and used is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

Assets Held for Sale: Recoverability of assets held for sale is measured by comparing the carrying amount of an asset to its fair value less the cost to sell. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value less estimated costs to sell.

(m) Variable interest entities

The Company performs analysis to assess whether its operations and investments represent variable interest entities (“VIEs”). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities. VIEs of which the Company is deemed the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated.

Long Sault is a hydroelectric generating facility in which APUC acquired an interest by way of subscribing to two notes from the original developers. The notes receivable effectively provide APUC the right to 100% of after tax cash flows of the facility up to the end of 2013, 65% from 2014 to 2027 and 58% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. APUC has determined that the facility is a VIE since the Company is the primary beneficiary and therefore the Long Sault entity is subject to consolidation by the Company. Total net book value of generating assets and long-term debt of Long Sault amounts to $41,260 (2011 - $46,160) and to $37,143 (2011 - $38,136), respectively. The financial performance of Long Sault reflected on the statement of operations includes non-regulated energy sales of $8,747 (2011 - $9,804), operating expenses and amortization of $2,728 (2011 - $3,001) and interest expense of $3,929 (2011 - $3,984).

(n) Long-term investments and notes receivable

Investments in which APUC has significant influence but not control are accounted using the equity method. APUC records its share in the income or loss of its investees in interest, dividend and other income in the Consolidated Statement of Operations.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable that exceed one year and bear interest at a market rate based on the customer’s credit quality are initially recorded at cost, which is generally face value. Subsequent to acquisition, they are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity.

An allowance for impairment loss on notes receivable is recorded if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note’s effective interest rate.

ALGONQUIN POWER & UTILITIES CORP.

Notes to the Consolidated Financial Statements
December 31, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

1. Significant accounting policies (continued)

(o) Advances in aid of construction

The Company's regulated utilities have various agreements with real estate development companies (the "developers") conducting business within the Company's utility service territories, whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development. These amounts are recorded as Advances in Aid of Construction in other long-term liabilities. In many instances, developer advances can be subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods generally ranging from 10 to 20 years. Advances not refunded within the prescribed period are usually not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to the cost of property, plant and equipment. In 2012, $3,207 (2011 - $1,107) was transferred from advances in aid of construction to contributions in aid of construction.

(p) Deferred water rights and customer deposits

Deferred water rights are related to a hydroelectric generating facility which has a fifty year water lease with the first ten years of the water lease requiring no payment, which is a form of lease inducement. An annual average rate for water rights was estimated for the entire life of the lease and that average rate is being expensed over the lease term. The result of this policy is that the deferred water rights inducement amount recorded in the first ten years is being drawn down in the last forty years.

Customer deposits result from the Liberty Utilities' obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement. The deposits bear monthly interest and are applied to the customer account after 12 months if the customer is found to be credit worthy.

(q) Pension and other post employment plans

The Company has established defined contribution pension plans, defined benefit pension plans, and other post-employment benefit ("OPEB") plans for its various employee groups in Canada and the United States. The Company recognizes the funded status of its defined benefit pension plans and other post employment benefit plans on the Consolidated Balance Sheets. The Company's expense and liabilities are determined by actuarial valuations, using assumptions that are evaluated annually at December 31, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates and healthcare cost trend rates. The impact of modifications to those assumptions is recorded as actuarial gains and losses in accumulated other comprehensive income and amortized to net periodic cost over future periods using the corridor method. The costs of the Company's pension for employees are expensed over the periods during which employees render service and are recognized as part of administrative expenses in the Consolidated Statement of Operations. The portion of pension and OPEB costs capitalized as cost of construction of plant and equipment is insignificant.

ALGONQUIN POWER & UTILITIES CORP.

Notes to the Consolidated Financial Statements
December 31, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

1. Significant accounting policies (continued)

(r) Asset retirement obligations

The Company recognizes a liability for asset retirement obligations based on the fair value of the liability when incurred, which is generally upon acquisition, construction, development or through the normal operation of the asset. Concurrently, the Company also capitalizes an asset retirement cost, equal to the estimated fair value of the asset retirement obligation, by increasing the carrying value of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in depreciation expense on the Consolidated Statements of Operations, or regulatory assets when the amount is recoverable through rates. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statements of Operations, or regulatory assets when the amount is recoverable through rates. Actual expenditures incurred are charged against the accumulated obligation.

(s) Stock based compensation

The Company has several share-based compensation plans: a share option plan; an employee common share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. The Company recognizes all employee stock-based compensation as a cost in the financial statements. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value of options using the Black-Scholes option pricing model.

(t) Noncontrolling interests

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to the equity holders of the parent Company. Noncontrolling interests are initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of earnings and other comprehensive income attributable to the non-controlling interests and any dividends or distributions paid to the noncontrolling interests.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net earnings or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Certain of the Company's U.S. based wind businesses (see note 3(d)) are organized as limited liability corporations and partnerships and have noncontrolling Class A membership equity investors which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the noncontrolling interest holders in these subsidiaries is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting. HLBV uses a balance sheet approach, which measures the allocation of income or loss of the Class A's membership in each period by calculating the change in the amount of distribution the partners would contractually be entitled to based on a hypothetical liquidation of the book value carrying amounts of the entity at the beginning of a reporting period compared to the end of that period.

ALGONQUIN POWER & UTILITIES CORP.

Notes to the Consolidated Financial Statements
December 31, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

1. Significant accounting policies (continued)

(u) Recognition of revenue

Revenue derived from non-regulated energy generation sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Revenues related to utility electricity and natural gas sales and distribution are recorded based on metered consumptions by customers, which occur on a systematic basis throughout a month, rather than when the electricity or natural gas is delivered. At the end of each month, the electricity and natural gas delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled sales and revenues are based on the ratio of billable days versus unbilled days, amount of electricity or natural gas procured during that month, historical customer class usage patterns, weather, line loss, unaccounted-for gas and current tariffs.

Water reclamation and distribution revenues are recorded when water is processed or delivered to customers. At the end of each month, the water delivered and waste water collected from the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled revenues are based on the ratio of billable days versus unbilled days, amount of water procured and collected during that month, historical customer class usage patterns and current tariffs.

Revenue from waste disposal is recognized on actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts is recognized based on actual tonnage at the expected price for the contract year.

Interest from long-term investments is recorded as earned.

(v) Foreign currency translation

The Company's reporting currency is the Canadian dollar.

The Company's US operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date while revenues and expenses are converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of other comprehensive income ("OCI") and are accumulated in a component of equity on the Consolidated Balance Sheet and are not recorded in income unless there is a complete or substantially complete sale or liquidation of the investment.

ALGONQUIN POWER & UTILITIES CORP.

Notes to the Consolidated Financial Statements
December 31, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

1. Significant accounting policies (continued)

(w) Income taxes

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the date of enactment. Income tax credits are treated as a reduction to current income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company follows ASC 740-10 and recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(x) Financial instruments and derivatives

APUC has classified its cash and cash equivalents and restricted cash as held-for-trading, which are measured at fair value. Accounts receivable and notes receivable are measured at amortized cost and there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the respective asset's carrying value at inception. Transaction costs for items classified as held-for-trading are expensed immediately. Transaction costs that are directly attributable to the issuance of financial liabilities, costs of arranging the Company's credit facility and costs considered as commitment fees paid to financial institutions are recorded in deferred financing costs. Deferred financing costs, premiums and discounts on long-term debt are amortized using the effective interest method while deferred financing costs relating to revolving credit facilities are amortized on a straight-line basis over the term of the facility.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities in the Consolidated Balance Sheet at their respective fair values. During 2011, none of the derivatives were designated in hedging relationships for accounting purposes and, as a result, the changes in the fair value were immediately recognized in the Consolidated Statements of Operations. In 2012, the Company commenced applying hedge accounting to financial instruments used to manage its foreign currency risk exposure and price risk exposure associated with sales of generated electricity.

ALGONQUIN POWER & UTILITIES CORP.

Notes to the Consolidated Financial Statements
December 31, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

1. Significant accounting policies (continued)

(x) Financial instruments and derivatives (continued)

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized as other comprehensive income. The ineffective portion is immediately recognized in earnings. The amount recognized in accumulated other comprehensive income is removed and included in earnings in the same period as the hedged cash flows affect earnings under the same line item in the statement of income as the hedged item. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated, exercised, or the designation is revoked, then hedge accounting is discontinued prospectively. The amount recognized in accumulated other comprehensive income is transferred to the income statement in the same period that the hedged item affects profit or loss. If the forecast transaction is no longer expected to occur, then the balance in accumulated other comprehensive income is recognized immediately in earnings.

For derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations, foreign currency transaction gain or loss that are designated as, and are effective as, an economic hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in other comprehensive income) related to the net investment. To the extent that the hedge is ineffective, such differences are recognized in earnings.

Liberty Energy (California) (“Calpeco”) and Granite State Electric Company (“Granite State”) enter into Power Purchase Agreements (“PPA”) for load serving requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be recorded at fair value as derivatives and are accounted for on an accrual basis. Counterparties are evaluated on an on-going basis for non-performance risk to ensure it does not impact the conclusion with respect to this exemption.

(y) Fair value measurements

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

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

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Notes to the Consolidated Financial Statements
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1. Significant accounting policies (continued)

(x) Financial instruments and derivatives (continued)

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized as other comprehensive income. The ineffective portion is immediately recognized in earnings. The amount recognized in accumulated other comprehensive income is removed and included in earnings in the same period as the hedged cash flows affect earnings under the same line item in the statement of income as the hedged item. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated, exercised, or the designation is revoked, then hedge accounting is discontinued prospectively. The amount recognized in accumulated other comprehensive income is transferred to the income statement in the same period that the hedged item affects profit or loss. If the forecast transaction is no longer expected to occur, then the balance in accumulated other comprehensive income is recognized immediately in earnings.

For derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations, foreign currency transaction gain or loss that are designated as, and are effective as, an economic hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in other comprehensive income) related to the net investment. To the extent that the hedge is ineffective, such differences are recognized in earnings.

Liberty Energy (California) (“Calpeco”) and Granite State Electric Company (“Granite State”) enter into Power Purchase Agreements (“PPA”) for load serving requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be recorded at fair value as derivatives and are accounted for on an accrual basis. Counterparties are evaluated on an on-going basis for non-performance risk to ensure it does not impact the conclusion with respect to this exemption.

(y) Fair value measurements

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

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

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1. Significant accounting policies (continued)

(z) Commitments and contingencies

Liabilities for loss contingencies arising from environmental remediation, claims, assessments, litigation, fines, and penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

(aa) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment and intangible assets, the annual impairment testing of reporting units containing goodwill, the recoverability of notes receivable and long-term investments, the recoverability of deferred tax assets, assessments of unbilled revenue, pension and OPEB obligations, contingencies related to environmental matters, and the fair value of financial instruments, derivatives and share-based compensation. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

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2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

In May 2011, the FASB issued ASU No. 2011-04 “Fair Value Measurement (Topic 820)”. This ASU amends the accounting and disclosure requirements for fair value measurements. The new guidance expands the disclosures about fair value measurements categorized within Level 3 of the fair value hierarchy and requires categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. The adoption of this guidance in 2012 did not have a material impact on the Company’s consolidated financial statements.

(b) Recent accounting guidance not yet adopted

The FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities and ASU 2013-01 Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. These newly issued accounting standards require an entity to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions executed under a master netting or similar arrangement and was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on an entity’s financial position. These ASU are required to be applied retrospectively and are effective for fiscal years, and interim periods beginning on or after January 1, 2013. As these accounting standards only require enhanced disclosure, the adoption of these standards is not expected to have an impact the Company’s financial position or results of operations.

The FASB issued ASU 2013-02, Comprehensive Income (Topic 220). This newly issued accounting standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This ASU is required to be applied prospectively for fiscal years, and interim periods beginning after December 15, 2012. As this accounting standard only requires enhanced disclosure, the adoption of this standard is not expected to have an impact the Company’s financial position or results of operations.

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3. Business acquisitions and development projects

(a) Acquisition of New Hampshire electric and gas utilities

On July 3, 2012, Liberty Utilities acquired 100% of the common shares of Granite State Electric Company, a regulated electric utility, and EnergyNorth Natural Gas Inc. ("EnergyNorth") a regulated natural gas utility for total cash consideration of $299,501 (U.S. $295,805) subject to final closing adjustments.

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

	Granite State	EnergyNorth	Total
Cash	$ 395	$ -	$ 395
Restricted cash	3,314	-	3,314
Working capital	1,778	25,255	27,033
Property, plant and equipment	86,935	256,305	343,240
Regulatory assets	32,068	87,203	119,271
Deferred financing	31	-	31
Other assets	172	83	255
Goodwill	-	27,580	27,580
Customer deposits	(661)	(962)	(1,623)
Long-term debt	(15,187)	-	(15,187)
Other long-term liabilities	(1,193)	(4,493)	(5,686)
Advances in aid of construction	-	(86)	(86)
Derivative liabilities	-	(2,601)	(2,601)
Regulatory liabilities	(5,494)	(27,572)	(33,066)
Pension and OPEB	(19,108)	(29,197)	(48,305)
Environmental obligation	-	(54,431)	(54,431)
Deferred income tax liabilities, net	-	(60,633)	(60,633)
	$ 83,050	$ 216,451	$ 299,501
Less: Cash acquired	(395)	-	(395)
Total net assets acquired	$ 82,655	$ 216,451	$ 299,106

The determination of the fair value of assets and liabilities acquired has been based upon management's preliminary estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. The Company has not completed the fair value measurements. In addition, the purchase agreements provides for a final purchase price adjustment based on final agreed working capital and rate base balances at the acquisition date. The Company will continue to review information and perform further analysis prior to finalizing the fair value of the consideration paid and the fair value of the assets acquired and liabilities assumed. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts above.

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

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3. Business acquisitions and development projects (continued)

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

Property, plant & equipment are amortized in accordance with regulatory requirements which are generally over the estimated useful lives of the assets using the straight line method. The weighted average life of the acquired assets of EnergyNorth and Granite State are 40 years and 28 years respectively.

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

Granite State and EnergyNorth contributed revenue of $86,993 and a net loss of $354 to the Company's results in 2012. Pro forma financial information is disclosed in note 3 (c).

(b) Acquisition of Midwest Gas Utilities

On August 1, 2012, Liberty Utilities acquired certain regulated natural gas distribution utility assets (the "Midwest Gas Utilities") located in Missouri, Iowa, and Illinois. The total purchase price for the Midwest Utilities was approximately $128,890 (U.S. $128,223), subject to final closing adjustments.

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

Working capital and restricted cash	$ 7,130
Property, plant and equipment	123,631
Regulatory assets	146
Deferred income tax assets, net	9,215
Goodwill	25,162
Current portion of long-term liabilities	(1,841)
Current portion of derivative liabilities	(547)
Advances in aid of construction	(276)
Regulatory liabilities	(28,581)
Pension and OPEB	(5,149)
Total net assets acquired	$128,890

The determination of the fair value of assets and liabilities acquired has been based upon management's preliminary estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. The Company has not completed the fair value measurements. In addition, the purchase agreements provides for a final purchase price adjustment based on final agreed working capital and rate base balances at the acquisition date. The Company will continue to review information and perform further analysis prior to finalizing the fair value of the consideration paid and the fair value of the assets acquired and liabilities assumed. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts above.

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3. Business acquisitions and development projects (continued)

(b) Acquisition of Midwest Gas Utilities (continued)

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

Property, plant & equipment are amortized in accordance with regulatory requirements over the estimated useful life of the asset using the straight line method. The weighted average life is 30 years.

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

Midwest Gas Utilities contributed revenue of $25,936 and net earnings of $1,229 to the Company's results in 2012. Pro forma financial information is disclosed in note 3 (c).

(c) Pro forma financial information

The supplemental pro forma financial information below was prepared using the acquisition method of accounting and is based on the historical financial information of APUC, Granite State, EnergyNorth and the Midwest Gas Utilities, reflecting results of operations for the years ended December 31, 2012 and 2011 on a comparative basis as though the aforementioned companies were combined as of the beginning of fiscal year 2011. The estimated acquirees' pre-acquisition results have been added to APUC's historical results, and the totals have been adjusted for the pro forma effects of acquisition-related costs, interest expense related to the financing of the business combinations, and related income taxes.

Pro forma	**2012**	**2011**
Total revenue	$ 521,538	$ 574,618
Net earnings attributable to APUC	22,584	33,328
Basic net earnings per share	0.14	0.23
Diluted net earnings per share	0.14	0.23

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

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3. Business acquisitions and development projects (continued)

(d) Acquisition of U.S. wind farms

On July 1, 2012, APCo acquired a 51% controlling interest in the Pennsylvania based 50MW Sandy Ridge Wind Project ("Sandy Ridge") for approximately $30,121 (U.S. $29,749). In October, APCo acquired an additional 7.75% interest for U.S. $4,521.

On December 10, 2012, APCo acquired a 58.75% controlling interest in both the 150 MW Senate Wind Project ("Senate") in Texas and the 200 MW Minonk Wind Project ("Minonk") in Illinois for approximately $87,646 (U.S. $88,801) and $143,652 (U.S. $145,544), respectively. On the same date, APCo acquired an additional 1.25% interest in all three projects bringing the total interest to 60% for additional consideration of U.S. $ 3,100.

The three wind projects are being acquired through Wind Portfolio Holdings LLC., a newly formed partnership whose members include Class B members consisting of APCo, through one of its subsidiaries, (holding a 60% controlling Class B interest) and Gamesa Corporación Tecnológica, S.A. (“Gamesa”), the original developer of the projects, (holding a 40% interest in Class B membership units) and certain Class A equity investors. In exchange for the cash contributed, the Class A members will receive a portion of the economic attributes of the facility, including Production Tax Credits, allocated taxable income or loss and cash distributions, until the date they achieve the targeted internal rate of return (the ‘Flip Date’) on their investment. Pursuant to the allocation rules specified in the LLC operating agreement, all operating cash flow is allocated to the Class B members until the earlier of a fixed date, or when the Class B members recover the amount of invested Class B capital. This is expected to occur between five to seven years from the initial closing date. Thereafter, 65% of operating cash flow is allocated to the Class A members until the Flip Date, which is expected to occur between eight and ten years from the initial closing date. After the initial year until the Flip Date, substantially all of the taxable income and benefits generated by the partnerships are allocated to the Class A members, with any remaining benefits allocated to the Class B members.

The following table summarizes the assets acquired and liabilities assumed at the acquisition dates. The equity interests show APCo’s total interest of 60% to reflect the nature of the transaction:

	Sandy Ridge	Senate	Minonk	Total
Cash	$ 1,365	$ 5,336	$ 16,528	$ 23,229
Property, plant and equipment	87,278	287,111	380,744	755,133
Derivative asset (liability)	1,655	(8,639)	3,736	(3,248)
Working capital	(1,365)	(5,336)	(16,528)	(23,229)
Asset retirement obligation	(1,662)	(1,697)	(2,262)	(5,621)
Total net assets acquired	$ 87,271	$ 276,775	$ 382,218	$ 746,264

Equity interests:				
APCo Class B membership interest	$ 35,169	$ 88,748	$ 145,151	$ 269,068
Additional paid in capital	192	919	1,250	2,361
Noncontrolling interests:				
Class A members	28,211	127,590	137,703	293,504
Class B members	23,699	59,518	98,114	181,331
	$ 87,271	$ 276,775	$ 382,218	$ 746,264

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3. Business acquisitions and development projects (continued)

(d) Acquisition of U.S. wind farms (continued)

Property, plant & equipment are amortized on a straight line basis over the lives of the assets, which have a weighted average life of 32 years.

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

The contribution of the U.S. wind farms to the Company's results in 2012 was as follows:

	Revenue	Net earnings/(Loss)
Sandy Ridge	$ 2,132	$ (353)
Senate	1,179	50
Minonk	785	(146)
	$ 4,096	$ (449)

The disclosure of pro forma revenue and net earnings is impracticable as there is no historical financial information since APCo acquired the wind farms shortly after commencement of commercial operations.

(e) Acquisition of noncontrolling interest in Calpeco

On December 21, 2012, APUC acquired the 49.999% interest in Calpeco from Emera Inc.("Emera") for $38,756 which was funded by the proceeds of common share subscription receipts (note 14(a)(iii)). The impact on the Company's Consolidated Balance Sheet was as follows:

Elimination of noncontrolling interest (net of intercompany balance of $1,297 with Emera)	$ 33,726
Noncontrolling interest portion of currency translation adjustment transferred to AOCI	1,397
Accumulated deficit	3,633
Exercise of subscription receipts	$ 38,756

(f) Acquisition of solar energy project

On January 4, 2012, APCo acquired rights to develop a 10 MWac solar project located near Cornwall, Ontario which has been granted a Feed-in-Tariff contract by the Ontario Power Authority for a 20 year term at a rate of $443/MWh. The consideration for the development rights is $4,500 plus additional contingent consideration of $3,500 based on achieving certain construction milestones. As at December 31, 2012, the Company has paid a total of $2,000 based on achieved milestones. The transaction has been recorded as a purchase of intangible assets.

(g) Acquisition of Shady Oaks wind power facility

Subsequent to year-end, effective January 1, 2013, APCo acquired the 109.5 MW Sandy Oaks wind powered generating facility by assuming the existing long-term debt of approximately U.S. $150 million for no additional cash. The purchase agreement provides for final purchase price adjustments based on working capital at the acquisition date, energy generated by the project and basis differences between the relevant node and hub prices. The energy and basis related price adjustment will be based on the project's experience from January 1, 2013 to June 30, 2014.

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3. Business acquisitions and development projects (continued)

(g) Acquisition of Shady Oaks wind power facility (continued)

The current portion of the long-term debt of U.S. $25,000 and U.S. $3,000 are payable on June 30 and November 15, 2013, respectively. The semi-annual principal repayment schedule for the following 11 years ranges from $3,000 to $6,000 with a final repayment of U.S. $20,000 in 2025. This debt may be repaid in whole or in part at anytime without penalty and bears interest at Libor plus 280 basis points.

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

Based on the timing of the completion of this acquisition in relation to the date of issuance of the financial statements, the initial allocation of the consideration paid has not been completed.

(h) Agreement to acquire Regulated Gas Utility in Georgia

On August 8, 2012, Liberty Utilities entered into an agreement with Atmos Energy Corporation (“Atmos”) to acquire certain regulated natural gas distribution utility assets (the “Georgia Utility”) located in the State of Georgia. Total purchase price for the Georgia Utility is approximately U.S. $140,660, subject to certain working capital and other closing adjustments. Regulatory approval was obtained in February 2013 and the acquisition is expected to close on or about April 1, 2013.

(i) Acquisition of Arkansas Regulated Water Utility

Subsequent to year-end, on February 1, 2013, Liberty Utilities acquired United Water Arkansas Inc. a regulated water distribution utility (the “Arkansas Utility”) located in Pine Bluff, Arkansas. Total purchase price for the Arkansas Utility is approximately U.S. $27,600, subject to certain working capital and other closing adjustments.

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

Based on the timing of the completion of this acquisition in relation to the date of issuance of the financial statements, the initial allocation of the consideration paid has not been completed.

(j) Agreement to acquire New England Gas Company

Subsequent to year-end, on February 11, 2013, Liberty Utilities entered into an agreement with The Laclede Group, Inc. to assume the rights to purchase the assets of New England Gas Company (“New England Gas”) located in the State of Massachusetts. Total purchase price for the New England Gas is approximately U.S. $74,000, subject to certain working capital and other closing adjustments. Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in the second half of 2013.

4. Accounts receivable

Accounts receivable as of December 31, 2012, includes unbilled revenue of $22,658 (December 31, 2011 - $11,304) in the regulated utilities. The unbilled revenue is an estimate of the amount of utility revenue since the date the meters were last read that has not yet been billed to customers.

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5. Property, plant and equipment

Property, plant and equipment consist of the following:

2012

	Cost	Accumulated depreciation	Net book value
Generation			
Renewable	1,244,912	$119,809	$1,125,103
Thermal	208,183	78,336	129,847
Distribution			
Water & wastewater	240,376	52,162	188,214
Electricity	259,461	7,765	251,696
Gas	352,491	5,940	346,551
Land	12,006	-	12,006
Equipment	71,954	26,697	45,257
Construction in progress	64,041	-	64,041
	$ 2,453,424	$ 290,709	$ 2,162,715

2011

	Cost	Accumulated depreciation	Net book value
Generation			
Renewable	$488,920	$117,740	$371,180
Thermal	194,080	78,776	115,304
Distribution			
Water & wastewater	239,190	48,716	190,474
Electricity	154,154	2,636	151,518
Land	11,981	-	11,981
Equipment	47,599	21,865	25,734
Construction in progress	53,918	-	53,918
	$ 1,189,842	$ 269,733	$ 920,109

Renewable generation assets include cost of $88,198 (2011 - $94,606) and accumulated depreciation of $29,584 (2011 - $30,264) related to facilities under capital lease or owned by consolidated variable interest entities. Depreciation expense of facilities under capital lease was $2,244 (2011 - $2,302).

Equipment includes cost of $4,227 (2011 - $4,227) and accumulated depreciation of $2,348 (2011 - $2,079) related to equipment under capital lease. Depreciation expense of equipment under capital lease was $269 (2011 - $282).

Contributions received in aid of construction of $6,341 (2011 - $3,968) have been credited to the cost of the distribution assets. Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

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5. Property, plant and equipment (continued)

In 2012, APCo wrote down its investment in a small hydro facility and recognized an impairment charge on property, plant and equipment of $253 (2011 - $1,370) representing the difference between the carrying value of the assets and their estimated fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities and management's best estimates.

In December 2011, Liberty Utilities wrote down $1,058 from facilities` assets based on regulatory decisions in 2011 that these costs are not capitalizable for rate-base purposes.

6. Intangible assets

Intangible assets consist of the following:

2012

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 60,435	$ 24,881	$ 35,554
Customer relationships	26,674	5,447	21,227
	$ 87,109	$ 30,328	$ 56,781

2011

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 52,073	$ 19,123	$ 32,950
Customer relationships	27,206	4,887	22,319
	$ 79,279	$ 24,010	$ 55,269

The Region of Peel elected not to extend the existing waste processing contract with the Company. As a result, the remaining intangible assets associated with the existing waste management and energy contracts of the facility were written off in 2011 and the Company recognized a charge on intangible assets of $13,430.

Estimated amortization expense for intangibles for the next four years is $4,200 each year and $2,450 in year five.

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5. Property, plant and equipment (continued)

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7. Regulatory matters

The Company's regulated utility operating companies owned by Liberty Utilities are subject to regulation by the respective public utility commissions of the states in which they operate, and the FERC in some instances. The respective state public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities.

The utilities periodically file rate cases with their regulators. 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. Regulated utilities use a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined.

Liberty Utilities 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.

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7. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

	2012	2011
Regulatory assets:		
Environmental costs (a)	$ 59,789	$ -
Pension and post-retirement benefits (b)	47,838	-
Storm costs deferral (c)	6,726	-
Deferred energy costs (d)	7,962	-
Derivative assets (e)	1,731	-
Rate case costs (f)	4,480	2,161
Alternative revenue program (g)	272	2,789
Asset retirement obligation (h)	1,095	-
Other	4,499	79
Total regulatory assets	$134,392	$ 5,029
Less current regulatory assets	(10,644)	(2,458)
Non-current regulatory assets	$123,748	$ 2,571
Regulatory liabilities		
Cost of removal (i)	$ 58,852	$ 14,945
Rate-base offset (j)	15,541	-
Energy costs adjustment (d)	11,706	6,708
Pension and post-retirement benefits (b)	1,127	-
Derivative liabilities (e)	616	-
Other	273	-
Total regulatory liabilities	$ 88,115	$ 21,653
Less current regulatory liabilities	(6,065)	(2,469)
Non-current regulatory liabilities	$ 82,050	$ 19,184

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7. Regulatory matters (continued)

(a) Environmental remediation costs recovery: EnergyNorth is responsible for the cleanup of certain former gas manufacturing facilities. Actual expenditures are recovered through rates over a period of 7 years (see note 21 (a) (ii)).

(b) Pension and post-retirement benefits: As part of a business acquisition, a regulatory asset or liability is set up for the amounts of pension and post-retirement benefits that have not yet been recognized in net periodic cost and were presented as accumulated comprehensive income prior to the acquisition. The portion currently recovered through rates is amortized over the future services years of the employees. The portion related to the current acquisitions which amounts to U.S. $43,484 was authorized by the Regulator as a regulatory asset and recovery is expected to start following the next rate case.

(c) Storm costs: Granite State incurred repair costs resulting from certain storms, which are expected to be recovered through rates.

(d) Deferred energy cost: The revenue of the electric and natural gas utilities include a component which is designed to recover the cost of electricity or natural gas through rates charged to customers. Under deferred energy accounting, to the extent actual natural gas and purchased power costs differ from natural gas and purchased power costs recoverable through current rates that difference is not recorded on the consolidated statement of operations but rather is deferred and recorded as a regulatory asset or liability on the balance sheet. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of natural gas or electricity in future time periods, subject to regulatory review.

(e) Derivatives: Derivatives are utilized to manage the price risk associated with natural gas purchasing activities. The gains and losses associated with these derivatives are recoverable through its deferred energy cost, as noted above, (note 24(b)(i)).

(f) Rate case costs: The costs to file, prosecute and defend rate case applications are referred to as rate case costs. These costs are capitalized and amortized over the period of rate recovery granted by the regulator.

(g) Alternative revenue program: In 2011, the regulator of one of Liberty Utilities' utilities ordered to phase-in the rate increases it had granted over a 12 month period.

(h) Asset retirement obligation: Asset retirement obligations incurred by the utilities are expected to be recovered through rates.

(i) Cost of removal: The regulatory liability for cost of removal represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire the utility plant.

(j) Rate-base offset: The Regulator for the Midwest Gas Utilities imposed a rate base offset that would reduce the revenue requirement at future rate proceedings. The rate base offset declines on a straight-line basis over a period of ten years.

The Company records carrying charges on the regulatory balances related to energy costs, storm costs and rate adjustments. As recovery of regulatory assets is subject to regulatory approval, if there are any changes in regulatory positions that indicate recovery is not probable, the related cost would be charged to income in the period of such determination.

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8. Long-term investments and notes receivable

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

	2012	2011
Red Lily Senior loan, interest at 6.31% (a)	$ 11,588	$ 13,000
Red Lily Subordinated loan, interest at 12.5% (a)	6,565	6,565
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	4,926	4,926
25% of Class B non-voting shares of Cochrane Power Corporation	4,669	5,382
45% interest in the Algonquin Power (Rattle Brook) Partnership	3,884	3,784
Chapais Énergie, Société en Commandite interest at 10.789% and 4.91%, respectively	2,448	2,913
Silverleaf resorts loan, interest at 15.48% maturing July 2020	2,010	2,056
50% interest in the Valley Power Partnership	1,767	1,676
Other	326	-
	38,183	40,302
Less: current portion	(537)	(482)
Total long term investments and notes receivable	$ 37,646	$ 39,820

The above notes are secured by the underlying assets of the respective facilities. There is no impairment provision in regards to the notes receivable as at December 31, 2012 and 2011.

(a) Red Lily I

The Red Lily I Partnership ("Partnership") is owned by an independent investor. The Company provides operation and supervision services to the Red Lily I project, a 26.4 megawatt wind energy facility located in south-eastern Saskatchewan.

The Company's investment in Red Lily I is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility from the Partnership. In 2011, APUC advanced $13,000 under a senior debt facility to the Partnership and received a pre-payment of $1,412 in 2012. Another third party lender has also advanced $31,000 of senior debt to the Partnership. The Company's senior loan to the Partnership earns interest at the rate of 6.31% and will mature in 2016. Both tranches of senior debt are secured by substantially all the assets of the Partnership on a pari passu basis.

The subordinated loan earns an interest rate of 12.5%, the principal matures in 2036 but is repayable by the Partnership in whole or in part at any time after 2016, without a pre-payment premium. The subordinated loan is secured by substantially all the assets of the Partnership but is subordinated to the senior debt.

A second tranche of subordinated loan for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced in 2016 by the Company. 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.

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 loan of up to $19,500, exercisable for a period of 90 days commencing in 2016. The fair value of the conversion option as at December 31, 2012 and 2011 was determined to be negligible.

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9. Long-term liabilities

Long term liabilities consist of the following:

	2012	2011
APCo		
Revolving $200,000 credit facility, revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is BA or LIBOR plus 1.75%, maturing November 16, 2015.	$ 27,074	$ -
Senior Unsecured Notes: $150,000 senior unsecured notes, interest rate of 4.82% maturing February 15, 2021. The notes are interest only, payable semi-annually in arrears.	149,910	-
Senior Unsecured Notes: $135,000 senior unsecured notes, interest rate of 5.5% maturing July 25, 2018. The notes are interest only, payable semi-annually in arrears.	134,807	134,778
Senior Debt Long Sault Rapids: Interest at rate of 10.2% repayable in blended monthly interest and principal installments of $402 and maturing December 31, 2027.	38,136	39,033
Sanger Bonds: U.S. $19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bonds Series 1990A, interest payable monthly, maturing September 15, 2020. The variable interest rate is determined by the remarketing agent. The effective interest rate for 2012 is 2.29% (2011 – 2.05%).	19,102	19,526
Senior Debt Chute Ford: Interest rate of 11.6% repayable in blended monthly interest and principal installments of $64 and maturing April 1, 2020.	3,763	4,072
Liberty Utilities		
Revolving U.S. $100,000 credit facility, revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 1.625%, maturing January 18, 2015.	27,360	-
Senior Unsecured Notes:		
Liberty Utilities Co. Senior unsecured notes, U.S. $50,000, bearing an interest rate of 3.51%, maturing July 31, 2017; U.S. $115,000, bearing an interest rate of 4.49%, maturing August 1, 2022; and, U.S. $60,000, bearing an interest rate of 4.89%, maturing July 30, 2027. The notes are interest only, payable semi-annually.	223,852	-
California Pacific Electric Company, LLC: U.S. $45,000 senior unsecured notes, interest rate of 5.19%, maturing December 29, 2020 and U.S. $25,000, interest rate of 5.59%, maturing December 29, 2025. The notes are interest only, payable semi-annually.	69,643	71,190

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9. Long-term liabilities (continued)

	2012	2011
Liberty Water Co: U.S. $50,000 senior unsecured notes, interest rate of 5.6% maturing December 22, 2020. The notes are interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and an annual principal repayment of U.S. $5,000 thereafter.	49,745	50,850
Granite State: Senior unsecured notes, U.S. $5,000, bearing an interest rate of 7.37%, maturing November 1, 2023; U.S. $5,000, bearing an interest rate of 7.94%, maturing July 1, 2025; and, U.S. $5,000, bearing an interest rate of 7.30%, maturing June 15, 2028. The notes are interest only, payable semi-annually.	14,924	-
Litchfield Park Service Company Bonds: 1999 and 2001 IDA Bonds. Interest rates of 5.95% and 6.75% repayable in blended semi-annual installments maturing October 1, 2023 and October 1, 2031. Principal payments of U.S. $285 (2011 – U.S. $270). The balance of these notes at December 31, 2012 was U.S. $3,390 and U.S. $7,030, respectively (2011 – U.S. $3,605 and U.S. $7,100).	11,269	11,868
Bella Vista Water Loans: Water Infrastructure Financing Authority of Arizona Interest rates of 6.26% and 6.10% repayable in monthly and quarterly installments (U.S. $15 and U.S. $4) maturing March 1, 2020 and December 1, 2017. The balance of these notes at December 31, 2012 was U.S. $1,167 and U.S. $80 respectively (2011 – U.S. $1,275 and U.S. $83)	1,241	1,399
	$ 770,826	$ 332,716
Less: current portion	(1,768)	(1,624)
	$ 769,058	$ 331,092

Certain long-term debt issued at a subsidiary level relating to a specific operating facility is secured by the respective facility with no other recourse to APUC, APCo or Liberty Utilities. The loans have certain financial covenants, which must be maintained on a quarterly basis. Non compliance with the covenants could restrict cash distributions/dividends to Liberty Utilities, APCo and APUC from the specific facilities.

APCo

On December 3, 2012, APCo issued $150,000 senior unsecured debentures bearing interest at 4.82% and with a maturity date of February 15, 2021. The debentures were sold at a price of $99.94 per $100.00 principal amount. Interest payments will be payable on February 15 and August 15 each year, commencing on February 15, 2013. APCo incurred deferred financing costs of $1,057, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Concurrent with the offering, APCo entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars (note 24(b)(iii)).

In 2012, APCo increased the maximum availability under its senior credit facility from $120,000 to $200,000 to meet future working capital needs. In addition, the bank syndicate agreed to release its security previously held over certain APCo entities, such that the facility is now fully unsecured. The facility has a maturity date of November 16, 2015.

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9. Long-term liabilities (continued)

APCo (continued)

On July 25, 2011 APCo completed a $135,000 private placement debt financing at a price of $998.28 per $1,000 principal amount of debenture. The notes are senior unsecured with a maturity date of July 25, 2018 and bear interest at 5.5%. The notes are interest only, payable semi-annually in arrears, commencing January 25, 2012. APCo incurred deferred financing costs of $1,685, which are being amortized to interest expense over the term of the loan using the effective interest rate method. The net proceeds of this financing were used to retire the project debt related to the St. Leon facility (Air Source Senior Debt Financing) and to reduce amounts outstanding on APCo's senior secured revolving credit facility.

Liberty Utilities

Subsequent to year end, on March 14, 2013 Liberty Utilities entered into a variable rate unsecured U.S. $100,000 term facility with a U.S. Bank. Drawings under the facility are conditional upon closing of certain planned acquisitions by Liberty Utilities. The loan is non-revolving and matures on December 31, 2013.

Subsequent to year end, on March 14, 2013 Liberty Utilities issued U.S. $15,000 of senior unsecured notes through a private placement in connection with the acquisition of the Arkansas Utility (note 3 (h)). The notes bear interest at 4.14% and mature in 10 years.

In July 2012, Liberty Utilities issued U.S. $225,000 of senior unsecured notes through a private placement in three tranches: U.S. $50,000, bearing an interest rate of 3.51%, maturing July 31, 2017; U.S. $115,000, bearing an interest rate of 4.49%, maturing August 1, 2022; and, U.S. $60,000, bearing an interest rate of 4.89%, maturing July 30, 2027. The notes are interest only, payable semi-annually. Liberty Utilities incurred deferred financing costs of $2,663, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Liberty Utilities used the proceeds of the private placement financing to fund a portion of the acquisition of the New Hampshire and Midwest Gas Utilities (note 3(a), and (b)).

On July 3, 2012, in connection with the acquisition of Granite State, Liberty Utilities assumed senior unsecured long-term notes of U.S. $5,000, bearing an interest rate of 7.37%, maturing November 1, 2023; U.S. $5,000, bearing an interest rate of 7.94%, maturing July 1, 2025; and, U.S. $5,000, bearing an interest rate of 7.30%, maturing June 15, 2028.

On January 18, 2012, Liberty Utilities entered into an agreement for a senior unsecured revolving credit facility (the "Liberty Facility") with a three year term. Effective July 3, 2013, the maximum credit available under the facility is U.S. $100,000.

In 2011, Calpeco issued U.S. $70,000 senior unsecured notes consisting of U.S. $45,000 bearing an interest rate of 5.19% maturing December 29, 2020 and U.S. $25,000 bearing an interest rate of 5.59% maturing December 29, 2025. The notes are interest only, payable semi-annually. Total financing costs of $ 1,048 incurred with respect to this placement have been recorded in deferred financing costs.

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9. Long-term liabilities (continued)

APUC

On November 19, 2012, APUC entered into a $30 million senior unsecured revolving credit facility. The credit facility will be used for general corporate purposes and has a maturity date of November 19, 2015

As of December 31, 2012, the Company had accrued $4,482 in interest payable (2011 - $3,255). Interest paid on the long-term liabilities in 2012 was $20,671 (2011 - $18,089).

Principal payments due in the next five years and thereafter are:

	2013	2014	2015	2016	2017	Thereafter	Total
APCo	$1,339	$1,483	$28,721	$1,829	$2,032	$337,388	$372,792
Liberty Utilities	429	449	27,837	5,481	55,256	308,582	398,034
Total	$1,768	$1,932	$56,558	$7,310	$57,288	$645,970	$770,826

10. Convertible debentures

	Series 1A	Series 2A	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 September 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$4.08	$6.00	$4.20	
Carrying value at December 31, 2010	$ 59,156	$ 59,699	$ 62,905	$ 181,760
Conversion to common shares (Note14(a)(ii)), net of costs	(59,449)	(10)	(334)	(59,793)
Amortization and accretion	293	37	-	330
Carrying value at December 31, 2011	$ -	$ 59,726	$ 62,571	$ 122,297
Conversion to common shares (note 14(a)(ii)), net of costs	-	(59,950)	(61,611)	(121,561)
Amortization and accretion	-	224	-	224
Carrying amount at December 31, 2012	$ -	$ -	$960	$960
Face value at December 31, 2012	$ -	$ -	$960	$960

Subsequent to year-end, the remaining principal amount of $960 of Series 3 Debentures was redeemed for 150,816 shares of APUC (note 14(a)(ii)).

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11. Pension and other post-retirement benefits

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and OPEB plans for qualifying employees in the related acquired businesses. The electricity and gas utilities, other than Calpeco, each have noncontributory defined pension plans covering substantially all employees. Benefits are based on each employee's years of service and compensation. Calpeco has a defined benefit cash balance pension plan covering substantially all its employees, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The Company's policy is to make pension contributions within the range determined by generally accepted actuarial principles. The OPEB plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must cover a portion of the cost of their coverage.

The Company acquired EnergyNorth, Granite State and the Midwest Utilities in the third quarter of 2012; therefore, they are not included in the December 31, 2011 comparative information. The determination of the fair value of pension and OPEB assets and liabilities acquired has been based upon management's preliminary estimates and certain assumptions. Namely, plan assets acquired had not been transferred to the Company as at December 31, 2012. An estimate of the assets to be transferred adjusted for estimated return, contributions and benefits was used to estimate the funded status at the acquisition date and December 31, 2012. The Company will continue to review information and perform further analysis prior to finalizing the fair value of the pension and OPEB assets acquired and liabilities assumed. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts recorded.

(a) Net pension and OPEB obligation

The following table sets forth the projected benefit obligations, fair value of plan assets, and funded status of the Company's plans at December 31:

	Pension benefits		OPEB	
	2012	**2011**	**2012**	**2011**
Change in projected benefit obligation				
Projected benefit obligation, at beginning of year	$ 239	$ -	$ -	$ -
Assumed projected obligation from business combination	101,840	-	30,637	-
Service cost	1,288	180	803	-
Interest cost	1,906	-	606	-
Actuarial loss	2,736	52	857	-
Benefits paid	(1,507)	-	(601)	-
Foreign exchange	(2,211)	7	(628)	-
Projected benefit obligation, at end of year	$ 104,291	$ 239	$ 31,674	$ -
Change in plan asset				
Fair value of plan assets, at beginning of year	203	-	-	-
Acquired assets in business combination	68,045	-	10,786	-
Actual return on plan assets	1,223	-	-	-
Employer contributions	-	233	231	-
Benefits paid	(1,507)	-	(601)	-
(Gain)/Loss on foreign exchange	(1,440)	6	(221)	-
Fair value of plan assets, at end of year	$ 66,524	$ 239	$ 10,195	$ -
Unfunded status	$ (37,767)	$ -	$ (21,479)	$ -
Amounts recognized in the Consolidated Balance Sheet consists of:				
Current liabilities	-	-		-
Noncurrent liabilities	(37,767)	-	(21,479)	-
Net amount recognized	$ (37,767)	$ -	$ (21,479)	$ -

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11. Pension and other post-retirement benefits (continued)

(b) Net pension and OPEB obligation (continued)

The accumulated benefit obligation for the pension plan was $97,687 and $239 at December 31, 2012 and 2011, respectively.

The amounts recognized in accumulated other comprehensive loss were as follows:

	Accumulated other comprehensive income	
	Pension	**OPEB**
Balance, January 1, 2011		
Current year net actuarial loss	$ 47	$ -
Foreign exchange	1	-
Balance at December 31, 2011	$ 48	$ -
Current year net actuarial loss	3,303	857
Amortization of net actuarial loss	(2)	(32)
Foreign exchange	(16)	(4)
Balance at December 31, 2012	$ 3,333	$ 821

(c) Assumptions

Weighted average assumptions used to determine net benefit cost for 2012 and 2011 were as follows:

	Pension benefits		OPEB	
	2012	**2011**	**2012**	**2011**
Discount rate	3.89%	4.75%	3.97 %	N/A
Expected return on assets	5.50%	6.00%	4.66%	N/A
Rate of compensation increase	3.31%	4.00%	N/A	N/A
Healthcare cost trend rate				
Before Age 65			8.48%	N/A
Age 65 and after			7.50%	N/A
Assumed Ultimate Medical Inflation Rate			5.00%	N/A
Year in which Ultimate Rate is reached			2017	N/A

Weighted average assumptions used to determine net benefit obligation for 2012 and 2011 were as follows:

	Pension benefits		OPEB	
	2012	**2011**	**2012**	**2011**
Discount rate	3.62%	4.00%	3.75 %	N/A
Expected return on assets	5.50%	6.00%	4.66%	N/A
Rate of compensation increase	3.09%	4.00%	N/A	N/A

In selecting an assumed discount rate, the Company uses a modeling process that involves selecting a portfolio of high-quality corporate debt issuances (AA- or better) whose cash flows (via coupons or maturities) match the timing and amount of the Company's expected future benefit payments. The Company considers the results of this modeling process, as well as overall rates of return on high-quality corporate bonds and changes in such rates over time, to determine its assumed discount rate.

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11. Pension and other post-retirement benefits (continued)

(c) Assumptions (continued)

The effect of a one percent change in the assumed health care cost trend rate (HCCTR) for 2012 is as follows:

	2012
Effect of a 1 percentage point increase in the HCCTR on:	
Year-end benefit obligation	$ 4,153
Total service and interest cost	177
Effect of a 1 percentage point decrease in the HCCTR on:	
Year-end benefit obligation	$ (3,356)
Total service and interest cost	(142)

(d) Benefit costs

The following table lists the components of net benefit costs for the pension plans and OPEB recorded as part of administrative expenses in the Consolidated Statement of Operations. The employee benefit costs related to business acquired are recorded in the Consolidated Statement of Operations from the date of acquisition. The portion of employee benefit capitalized as cost of construction is insignificant.

	Pension benefits		OPEB	
	2012	2011	2012	2011
Service cost	$ 1,288	$ 180	$ 803	$ -
Interest cost	1,906	-	606	-
Expected return on plan assets	(1,785)	-	-	-
Amortization of net actuarial loss	2	-	32	-
Net benefit cost	$ 1,411	$ 180	$ 1,441	$ -

The net actuarial loss for the defined benefit pension plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $11 and $37, respectively.

(e) Plan assets

The Company's investment strategy for its pension and post-retirement plan assets is to maintain a diversified portfolio of assets with the primary goal of meeting long-term cash requirements as they become due. The total amount of plan assets acquired through business acquisitions in 2012 was determined but had not been transferred to the Company as at December 31, 2012. An estimate of the assets to be transferred adjusted for estimated return, contributions and benefits was used to estimate the funded status at December 31, 2012. Detailed investment allocation decisions will be finalized following the plan asset transfer that is expected to occur in the first quarter of 2013.

(f) Cash flows

The Company expects to contribute $2,309 to its pension plans and $1,311 to its postretirement benefit plans in 2013.

The expected benefit payments over the next ten years are as follows:

	2013	**2014**	**2015**	**2016**	**2017**	**2018-2022**
Pension plan	$ 4,269	$ 4,590	$ 4,693	$ 4,973	$ 5,262	$ 28,635
OPEB	1,311	1,416	1,520	1,588	1,663	10,008

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12. Other assets

Other assets consist of the following:

	2012	2011
Restricted cash	$ 7,063	$ 4,693
Deferred financing costs	8,706	8,503
Other	3,981	4,410
	19,750	17,606
Less: current portion	(833)	(833)
	$ 18,917	$ 16,773

13. Other long-term liabilities

Other long-term liabilities consist of the following:

	2012	2011
Asset retirement obligations	$ 7,088	$ -
Customer deposits	5,620	2,483
Provision for injury and damages	3,480	-
Deferred water rights inducement	2,845	2,927
Contingent consideration	1,031	1,080
Capital Leases:		
Obligation for equipment leases. Interest rates varying from 1.90% to 5.80%, monthly interest and principal payments with varying dates of maturity from March 2012 to December 2014	270	501
Other	4,907	5,073
	25,241	12,064
Less: current portion	(4,352)	(1,037)
	$ 20,889	$ 11,027

In conjunction with recent acquisitions, the Company assumed certain asset retirement obligations. These obligations have remained substantially unchanged since the acquisition date, except for normal accretion adjustments. The asset retirement obligations mainly relate to legal requirements to: (i) remove wind farm facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants) and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas main when removed from the pipeline system, (iii) clean and remove storage tanks containing waste oil and other waste contaminants, and (iv) remove asbestos upon major renovation or demolition of structures and facilities.

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14. Shareholders' capital

(a) Common shares

Number of common shares:

	2012	2011
Common shares, beginning of period	136,122,780	95,422,778
Public offering (i)	-	16,869,000
Conversion and redemption of convertible debentures (ii)	24,991,784	15,300,824
Conversion of subscription receipts (iii)	26,380,750	8,523,000
Issuance of shares under the dividend reinvestment and employee share purchase plans (iv) and (c(ii))	1,268,172	7,178
Common shares, end of period	188,763,486	136,122,780

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the Board); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC; subject to the rights of any shares having priority over the common shares, of which none are authorized or outstanding.

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.

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board of Directors of APUC.

(i) Public offering

In 2011, the Company issued 16,869,000 common shares at $5.65 per share pursuant to a public offering for proceeds of $95,310, net of issuance costs of $4,162.

(ii) Conversion and redemption of convertible debentures

In 2011, the remaining principal amount of $62,470 of Series 1A Debentures were redeemed for 15,219,641 common shares of APUC.

In 2012, the remaining principal amount of $59,957 (2011 - $10) of Series 2A Debentures were redeemed for 10,322,518 (2011 – 1,666) common shares of APUC.

In 2012, $61,611 (2011 - $334) of Series 3 Debentures were redeemed for 14,669,266 (2011 – 79,517) shares of APUC. Subsequent to year-end, the remaining principal amount of $960 Series 3 Debentures were redeemed for 150,816 common shares of APUC.

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14. Shareholders' capital (continued)

(a) Common shares (continued)

(iii) Subscription receipts

In January 2011, in connection with the acquisition of Calpeco, the Company issued 8,523,000 common shares at a price of $3.25 per share to Emera pursuant to a subscription receipt agreement. The $27,700 cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisition.

On May 14, 2012, in connection with the acquisition of Granite State and EnergyNorth, the Company issued 12,000,000 common shares at a price of $5.00 per share to Emera Inc. ("Emera") pursuant to a subscription receipt agreement. The $60,000 cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisitions.

On June 29, 2012, in connection with the acquisition of Sandy Ridge the Company received $15,000 from Emera relating to 2,614,006 subscription receipts representing a price of $5.74 per share and issued common shares relating to these subscription receipts in July 2012.

On July 31, 2012, in connection with the acquisition of the Midwest Gas Utilities the Company issued 6,976,744 common shares at a price of $6.45 per share to Emera pursuant to a subscription receipt agreement. The $45,000 cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisition.

On December 10, 2012, in connection with the acquisition of Senate and Minonk, the Company received $45,000 from Emera relating to the exercise of 7,842,016 subscription receipts at a price of $5.74 per subscription receipt pursuant to a subscription receipt agreement. The subscription receipts were converted to common shares subsequent to year end on February 14, 2013. The $45,000 cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisition.

On December 21, 2012, in connection with the acquisition of Emera's noncontrolling interest in Calpeco, the Company received $38,756 from Emera related to the exercise of 8,211,000 subscription receipts at a price of $4.72 per subscription receipt pursuant to a subscription receipt agreement. The $38,756 proceeds of the subscription receipts were used to fund the purchase of the noncontrolling interest. On December 27, 2012, Emera exercised 4,790,000 of these subscription receipts and the Company issued 4,790,000 common shares in exchange. Subsequent to year end, on February 14, 2013, the balance of 3,421,000 subscription receipts were exercised by Emera and the Company issued 3,421,000 common shares.

Following the above noted subscription receipts transactions, as of December 31, 2012 all subscriptions receipts had been exercised for cash and 11,263,016 of those subscriptions receipts had yet to be converted to the same number of common shares.

Subsequent to year end, on February 22, 2013, in connection with the proposed acquisition of the Georgia Utility, the Company agreed to issue 3,960,000 subscription receipts convertible into the same number of common shares upon conditions based on the acquisition of the Georgia Utility at a price of $7.40 per share to Emera.

(iv) Dividend reinvestment plan

The Company has a Common Shareholder Dividend Reinvestment Plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional Common Shares acquired through the reinvestment of cash dividends will be purchased in the open market or will be issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time. Subsequent to year-end, APUC issued an additional 324,051 shares under the dividend reinvestment plan.

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14. Shareholders' capital (continued)

(b) Preferred shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board of Directors of APUC. On November 9, 2012, APUC issued 4,800 Series A Preferred shares, at a price of $25 per share, for aggregate proceeds of $120,000 before issuance cost of $4,700.

The holders of preferred shares are entitled to receive fixed cumulative preferential dividends at an annual rate of $1.125 per share, payable quarterly, as and when declared by the Board of Directors of APUC (the "Board"). The Series A Preferred shares yield 4.5% annually for the initial six-year period up to, but excluding December 31, 2018, with the first dividend payment occurring December 31, 2012. The dividend rate will reset on December 31, 2018, and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94%. The Series A preferred shares are redeemable at $25 per share at the option of the Company on December 31, 2018, and on December 31 of every fifth year thereafter. The holders of Series A Preferred shares have the right to convert their shares into Cumulative Floating Rate Preferred shares, Series B ("the Series B Preferred shares"), subject to certain conditions, on December 31, 2018, and on December 31 of every fifth year thereafter. The Series B Preferred shares carry the same features as the Series A Preferred shares, except that holders will be entitled to receive quarterly floating-rate cumulative dividends, as and when declared by the Board, at a rate equal to the then ninety-day Government of Canada treasury bill yield plus 2.94%. The holders of Series B Preferred shares will have the right to convert their Shares back into Series A Preferred shares on December 31, 2018, and on December 31 of every fifth year thereafter. The Series A Preferred shares and the Series B Preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

Subsequent to year-end, effective January 1, 2013, the Company issued 100 redeemable Series C preferred shares in exchange for Class B limited partnership units issued by the St Leon LP. The mandatorily redeemable Series C preferred shares will be recorded as a liability on the Consolidated Balance Sheet (note 25).

(c) Share-based compensation

For the year ended December 31, 2012, APUC recorded $1,833 (2011 - $732) in total share-based compensation expense detailed as follows:

	2012	2011
Stock options	$ 1,376	$ 690
Directors deferred share units	155	-
Employee share purchase	42	9
Performance share units	260	33
Total share-based compensation	$ 1,833	$ 732

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14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2012, total unrecognized compensation costs related to non-vested options and share unit awards were $1,724 and $219 respectively, and are expected to be recognized over a period of 1.67 years and 1.80 years respectively.

i) Stock option plan

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

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

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historic volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

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14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

i) Stock option plan (continued)

The following assumptions were used in determining the fair value of share options granted:

	2012	2011
Risk-free interest rate	1.7%	3.0%
Expected volatility	38%	30%
Expected dividend yield	4.4%	5.3%
Expected life	8 years	8 years
Weighted average grant date fair value per option	$ 1.49	$ 0.99

Stock option activity during the period is as follows:

	Number of awards	Weighted average exercise price	Weighted average remaining contractual term (years)	Aggregate intrinsic value
Balance at January 1, 2012	2,487,105	$ 4.76	6.96	$ 4,134
Granted	1,263,622	6.24	8.00	-
Balance at December 31, 2012	3,750,727	$ 5.25	6.07	$ 5,939
Exercisable at December 31, 2012	1,215,770	$ 4.53	5.85	$ 2,805

Non-vested stock option activity during the period is as follows:

	Number of awards	Weighted Average Grant Date Fair value value
Non-vested options at January 1, 2012	2,100,369	$ 0.85
Granted	1,263,622	1.49
Vested	829,035	0.81
Non-vested options at December 31, 2012	2,534,956	$ 1.18

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14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

ii) Employee share purchase plan

Under the Company's employee share purchase plan ("ESPP"), eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match a) 20% of the employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of the employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually, for Canadian employees, and b) 15% of the employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. Shares purchased through the Company match portion shall not be eligible for sale by the participant for a period of one year following the contribution date on which such shares were acquired. At the Company's option, the shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2012, a total of 54,227 common shares (2011 – 7,176) were issued to employees under the ESPP plan.

iii) Directors deferred share units

Under the Company's Deferred Share Unit Plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in Deferred Share Units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. In 2012, 50,172 (2011 – nil) DSUs were issued pursuant to the election of the Directors to defer a percentage of their 2011 and 2012 Director's fee in the form of DSUs.

iv) Performance share units

The Company offers a performance share unit plan to its employees as part of the Company's long-term incentive program. Performance share units ("PSUs") are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of shares issued can range from 0% to 184% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividend's are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized ratably over the performance period based on the Company's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest.

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14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

iv) Performance share units (continued)

A summary of the PSUs follows; none of which are exercisable as at December 31, 2012:

	Number of awards	Weighted Average Grant-Date Fair Value	Weighted Average Remaining Contractual Term (years)	Aggregate intrinsic value
January 1, 2011	-	$ -	-	-
Granted	21,123	5.62	2.0	118,649
December 31, 2011	21,123	$ 5.62	2.0	135,610
Granted, including dividends	68,982	6.78	1.3	467,518
Forfeited	(6,622)	5.62	1.5	(37,196)
December 31, 2012	83,483	$ 6.58	1.8	571,025

15. Accumulated other comprehensive loss

Accumulated other comprehensive loss is comprised of the following balances, net of tax:

	2012	2011
Foreign currency cumulative translation adjustment	$ (105,959)	$ (96,462)
Unrealized gain on cash flow hedges	3,593	-
Pension and post-retirement actuarial loss	(2,501)	(48)
Total	$ (104,867)	$ (96,510)

16. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board of the Company. For the year ended December 31, 2012, the Company declared dividends to shareholders on common shares totaling $50,193 of which $42,850 were cash dividends (2011 - $32,426 of which were cash dividends) or $0.295 per common share (2011 - $0.24 per common share). The Board declared a dividend on the Company's common shares of $0.0775 per share payable on January 15, 2013 to the shareholders of record on December 31, 2012.

On December 31, 2012, an initial dividend of $0.1603 per share totaling $769, Series A, was paid in cash to Preferred Share, Series A holders of record on December 17, 2012.

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17. Income taxes

The provision for income taxes in the Consolidated Statements of Operations represents an effective tax rate different than the Canadian enacted statutory rate of 26.5% (2011 – 28.25%). The differences are as follows:

	2012	2011
Expected income tax expense / (recovery) at Canadian statutory rate	$2,527	$ 1,555
Increase (decrease) resulting from:		
Recognition of deferred credit	(5,092)	(6,581)
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates	(6,282)	(1,592)
Non-taxable corporate dividend	(666)	(591)
Non-controlling interests share of income	(2,835)	(1,317)
Production tax credit	(676)	-
Allowance for equity funds used during construction	(402)	-
Change in valuation allowances	-	(16,834)
Foreign currency on intercompany items	-	2,250
Other	(140)	563
Income tax recovery	$ (13,566)	$(22,547)

For the years ended December 31, 2012 and 2011, income/(loss) from continuing operations before taxes consists of the following:

	2012	2011
Canadian operations	$ 15,252	$ (5,242)
U.S. operations	(5,715)	10,749
	$ 9,537	$ 5,507

As a result of the business combination transaction in 2009, APUC recorded certain additional tax attributes. These tax attributes have been recognized to the extent management believes they are more likely than not to be realized. The excess of the carrying amount of the tax attributes recorded over the consideration was recorded as a deferred credit of $55,647 on the transaction date. The deferred credit is being recognized in income as a deferred income tax recovery in relative proportion to the amount of the related tax attributes that are utilized in the period.

Income tax expense (recovery) attributable to income/(loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2012			
Canada	$ 127	$ (137)	$ (10)
United States	611	(14,167)	(13,556)
	$ 738	$ (14,304)	$ (13,566)
Year ended December 31, 2011			
Canada	$ 268	$ (1,936)	$ (1,668)
United States	32	(20,911)	(20,879)
	$ 300	$ (22,847)	$ (22,547)

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17. Income taxes (continued)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2012 and 2011 are presented below:

	2012	2011
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	$ 184,845	$ 119,340
Outside basis in partnership	2,533	-
Financial derivatives	211	2,233
Pension and OPEB	5,011	-
Acquisition related costs	5,134	2,009
Regulatory accounts	9,407	4,313
Production tax credit	673	-
Reserves not currently deductible	1,276	-
Other	136	-
Total deferred income tax assets	209,226	127,895
Less: Valuation allowance	(15,062)	(15,062)
Total deferred tax assets	194,164	112,833
Deferred tax liabilities:		
Property, plant and equipment	(202,553)	(77,273)
Intangible assets	(5,478)	(7,812)
Other	-	(1,009)
Total deferred tax liabilities	(208,031)	(86,094)
Net deferred tax assets/(liabilities)	$ (13,867)	$ 26,739

The valuation allowance for deferred tax assets as of December 31, 2012 and 2011 was $15,062. The net change in the total valuation allowance was nil in 2012 and a decrease of $16,834 in 2011. The valuation allowance at December 31, 2012 was primarily related to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carry back and carry forward periods), projected future taxable income, and tax-planning strategies in making this assessment.

Deferred income taxes are classified in the financial statements as:

	2012	2011
Current deferred income tax asset	$ 10,567	$ 13,022
Non-current deferred income tax asset	77,497	67,671
Current deferred income tax liability	(1,133)	(723)
Non-current deferred income tax liability	(100,798)	(53,231)
	$ (13,867)	$ 26,739

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17. Income taxes (continued)

As at December 31, 2012, the Company had non-capital losses carry forwards available to reduce future year's taxable income, which expire as follows:

Year of expiry	Non-capital losses carry forwards
2015	$ 5,426
2026 and onwards	390,633
	$ 396,059

18. Sale of Small U.S. Hydro Facilities

On March 14, 2013, APCo entered into an agreement to sell 10 small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of the Company for gross proceeds of U.S. $27,000. In August 2012, APCo sold another small U.S. Hydro facility for gross proceeds of $350 for a loss on sale, net of tax of $253 which is included in the loss from discontinued operations. The operating results from these facilities are therefore disclosed as discontinued operations on the consolidated statements and prior periods have been reclassified to conform to this presentation.

The summary of operating results and cash flows from discontinued operations for the years ended December 31 is as follows:

	2012	2011
Non-regulated energy sales	2,870	5,921
Operating and administrative expenses	3,241	4,402
Depreciation of property, plant and equipment	1,279	1,405
Interest expense	4	4
Loss on sale of assets	253	-
Write-down of long-lived assets	-	1,354
Loss from discontinued operations, before income taxes	(1,907)	(1,244)
Income tax recovery	750	492
Loss from discontinued operations, net of income taxes	(1,157)	(752)
Add:		
Depreciation of property, plant and equipment	1,279	1,405
Loss on sale of assets	253	-
Write-down of long-lived assets	-	1,354
Less:		
Income tax recovery	(750)	(492)
Net cash (outflow) inflow from discontinued operations	(375)	1,515

Assets held-for-sale as at December 31, were as follows:

	2012	2011
Property, plant and equipment	24,390	25,847

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19. Related party transactions

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

Transactions with APMI and Senior Executives

APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the year ended December 31, 2012 were $333 (2011 - $327).

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. During the year ended December 31, 2012, APUC incurred costs in connection with the use of the aircraft of $598 (2011 - $453) and amortization expense related to the advance against expense reimbursements of $279 (2011 - $274). At December 31, 2012, the remaining amount of the advance was $nil (December 31, 2011 - $279).

Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon LP, a subsidiary of APUC and the legal owner of the St. Leon facility. The related holders of the Class B units received cash distributions of $292 for the year ended December 31, 2012 (2011 - $314). Subsequent to year-end, on January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the Class B units (notes 13 and 14 (b)).

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

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

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

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

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

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19. Related party transactions (continued)

Transactions with APMI and Senior Executives (continued)

As at December 31, 2012, included in amounts due from related parties is $816 (2011 - $663) owed to APUC from APMI and included in amounts due to related parties is $1,811 (2011 - $1,795) owed to APMI. These amounts arise from the transactions described above.

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

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

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

Transactions with Emera

In 2011, a subsidiary of Emera provided lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During the year ended December 31, 2012 APUC paid U.S. $nil (2011 – U.S. $260) in relation to this contract. In 2011, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

For the year ended December 31, 2012, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $6,096 (2011 – U.S. $6,564). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.

As of December 31, 2012, included in amounts due from related parties is $nil (2011 - $1,612) owed from Emera related to the unpaid contribution of their share of Liberty Energy (California) costs.

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

20. Basic and diluted net earnings per share

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

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20. Basic and diluted net earnings per share (continued)

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

	2012	2011
Net earnings attributable to shareholders of APUC	$ 14,532	$ 23,381
Preferred shares dividend	769	-
Net earnings attributable to common shareholders of APUC – Basic and Diluted	$ 13,763	$ 23,381
Weighted average number of shares		
Basic	158,304,340	116,712,934
Dilutive effect of share-based awards	605,281	249,854
Diluted	158,909,621	116,962,788

The shares potentially issuable as a result of the convertible debentures as well as stock options of 1,354,531 respectively (2011 – 1,326,900) are excluded from this calculation as they are anti-dilutive.

21. Commitments and contingencies

a) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements, with the exception of those matters described below. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

i) On October 21, 2011 the Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5,400 (including interest) to the government of Québec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $5,800. In 2012, the Company paid an amount of $1,884 (2011 - $ nil) to the government of Québec in relation to the early years covered by the claim in order to mitigate the impact of accruing interests on any amount ultimately determined to be payable or recoverable.

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21. Commitments and contingencies

a) Contingencies

ii) The normal ongoing operations and historic activities of the Company are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the United States Environmental Protection Agency and the New Hampshire Department of Environmental Services (“NHDES”). Like most other industrial companies, the gas and electric distribution utilities generate some hazardous wastes. Under federal and state Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of regulated utilities these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

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

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $59,862 (U.S. $60,168) which at a discount rate of 3.5% represents the recorded accrual of $56,587 at December 31, 2012. This amount reflects the approval from the NHDES on December 10, 2012 of a Conceptual Remedial Design Report submitted to NHDES for removal of tar-impacted media at the Liberty Hill Road Site in New Hampshire. The NHDES approval at Liberty Hill Road Site reduced the overall cost estimate and consequently the Company withdrew its pending appeal. Remediation costs estimates for each site may vary, depending upon changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered.

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, at December 31, 2012 the Company has reflected a regulatory asset of $59,789 for the MGP and related sites.

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

2013	$ 2,433
2014	13,316
2015	18,836
2016	14,236
2017	996
Thereafter to 2046	10,045
	$ 59,862

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21. Commitments and contingencies

b) Commitments (continued)

In addition to the commitments related to the proposed acquisitions disclosed in note 3 the following significant commitments exist at December 31, 2012.

As a result of the dam safety legislation passed in Quebec (Bill C93), APUC has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. The assessments have identified a number of remedial measures required to meet the new safety standards. APUC currently estimates further capital expenditures of approximately $16,900 over a period of five years related to compliance with the legislation.

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

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Purchased power	$56,276	$42,999	$41,316	$ -	$ -	$ -	$140,591
Gas delivery, service and supply agreements	25,165	16,792	14,977	5,777	5,207	52,461	120,379
Service agreements	27,147	18,610	17,827	22,253	23,023	566,903	675,763
Capital projects	3,110	500	-	-	-	-	3,610
Operating leases	4,405	4,099	3,792	3,284	3,202	69,562	88,344
Total	**$116,103**	**$83,000**	**$77,912**	**$31,314**	**$31,432**	**$688,926**	**$1,028,687**

Calpeco has entered into a five year all-purpose power purchase agreement with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2011 with a five year renewal option. The commitment amounts included in the table above are based on market prices as of December 31, 2012. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism. Granite State has several types of contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment.

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22. Non-cash operating items

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

	2012	2011
Accounts receivable	$ (14,895)	$ (11,674)
Related party balances	1,476	145
Supplies and consumable inventory	(3,621)	(1,087)
Income tax receivable	(423)	(133)
Prepaid expenses	(4,629)	(2,071)
Accounts payable	(7,553)	3,991
Accrued liabilities	31,105	9,010
Current income tax liability	131	207
Net regulatory assets and liabilities	(5,475)	70
	$ (3,884)	$ (1,542)

23. Segmented information

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

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

Effective July 2012, the Company changed its operational segments within Liberty Utilities to be aggregated and reported by the following geographic territories: Liberty Utilities (West), Liberty Utilities (Central) and Liberty Utilities (East). Liberty Utilities (West) is comprised of Calpeco and the water distribution and wastewater utilities located in Arizona. Liberty Utilities (Central) is comprised of the Midwest Gas Utilities and the water distribution and wastewater utilities located in Texas, Missouri and Illinois. Liberty Utilities (East) is comprised of the New Hampshire electric and gas utilities. The Company has restated the comparative items of segmented financial information to reflect the aggregation of segmented financial information adopted in the current year.

Operational segments

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

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

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22. Segmented information (continued)

Operational segments (continued)

	Year ended December 31, 2012								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ -	$ -	$ -	$ -	$ 71,734	$ 36,723	$ 108,457	$ -	$ 108,457
Regulated gas sales and distribution	-	-	-	25,802	-	49,916	75,718		75,718
Regulated water reclamation and distribution	-	-	-	9,127	37,296	-	46,423	-	46,423
Non-regulated energy sales	84,236	36,914	121,150	-	-	-	-	-	121,150
Waste disposal fees	-	14,288	14,288	-	-	-	-	-	14,288
Other revenue	1,925	1,680	3,605	-	152	94	246	-	3,851
Total revenue	86,161	52,882	139,043	34,929	109,182	86,733	230,844	-	369,887
Operating expenses	30,308	21,075	51,383	13,096	35,645	30,209	78,950	-	130,333
Regulated electricity purchased	-	-	-	-	43,861	24,348	68,209	-	68,209
Regulated gas purchased	-	-	-	13,648	-	23,813	37,461	-	37,461
Non-regulated fuel for generation	-	14,589	14,589	-	-	-	-	-	14,589
	55,853	17,218	73,071	8,185	29,676	8,363	46,224	-	119,295
Depreciation of property, plant and equipment	(18,823)	(9,977)	(28,800)	(3,333)	(11,120)	(7,129)	(21,582)	-	(50,382)
Amortization of intangible assets	(2,653)	(831)	(3,484)	(81)	(586)	-	(667)	-	(4,151)
Administration expenses	(9,424)	(2,212)	(11,636)	294	(4,091)	(1,223)	(5,020)	(2,952)	(19,608)
Foreign exchange gain	-	-	-	-	-	-	-	561	561
Interest expense	(15,060)	(2,054)	(17,114)	(96)	(8,066)	(694)	(8,856)	(9,971)	(35,941)
Interest, dividend and other income	2,038	509	2,547	-	2,113	461	2,574	2,118	7,239
Acquisition related costs	(3,155)	-	(3,155)	(1,442)	-	(3,112)	(4,554)	-	(7,709)
Gain/(loss) on derivative financial instruments	(2,954)	-	(2,954)	-			-	3,187	233
Earnings from continuing operations before income taxes	5,822	2,653	8,475	3,527	7,926	(3,334)	8,119	(7,057)	9,537
Loss from discontinued operations before income taxes	(1,907)	-	(1,907)	-	-	-	-	-	(1,907)
Earnings/(loss) before income taxes	$ 3,915	$ 2,653	$ 6,568	$ 3,527	$ 7,926	$ (3,334)	$ 8,119	$ (7,057)	$ 7,630
Property, plant and equipment	$1,157,062	$153,875	$1,310,937	$151,637	$350,053	$350,088	$851,778	$ -	$2,162,715
Intangible assets	29,480	6,132	35,612	2,613	18,556	-	21,169	-	56,781
Assets held for sale	24,390	-	24,390	-	-	-	-	-	24,390
Total assets	1,272,037	175,173	1,447,210	212,495	464,201	500,374	1,177,070	153,957	2,778,237
Capital expenditures	21,068	10,348	31,416	10,777	23,181	12,488	46,446	67	77,929
Acquisition of operating entities	245,718	-	245,718	128,890	-	295,297	424,187	-	669,905

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23. Segmented information (continued)

Operational segments (continued)

	Year ended December 31, 2011								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ -	$ -	$ -	$ -	$ 77,368	$ -	$77,368	$ -	$ 77,368
Regulated water reclamation and distribution	-	-	-	8,850	36,139	-	44,989	-	44,989
Non-regulated energy sales	81,645	46,666	128,311	-	-	-	-	-	128,311
Waste disposal fees	-	16,406	16,406	-	-	-	-	-	16,406
Other revenue	2,291	1,352	3,643	-	-	-	-	-	3,643
Total revenue	83,936	64,424	148,360	8,850	113,507	-	122,357	-	270,717
Operating expenses	25,400	19,857	45,257	4,270	34,453	-	38,723	38	84,018
Regulated electricity purchased	-	-	-	-	46,508	-	46,508	-	46,508
Non-regulated fuel for generation	-	24,628	24,628	-	-	-	-	-	24,628
	58,536	19,939	78,475	4,580	32,546	-	37,126	(38)	115,563
Depreciation of property, plant and equipment	(15,498)	(10,684)	(26,182)	(956)	(10,850)	-	(11,806)	-	(37,988)
Amortization of intangible assets	(3,007)	(2,735)	(5,742)	(81)	(610)	-	(691)	-	(6,433)
Administration expenses	(8,915)	(2,504)	(11,419)	(53)	(1,087)	-	(1,140)	(4,975)	(17,534)
Write down of long-lived assets	(678)	(13,430)	(14,108)		(1,058)		(1,058)	-	(15,166)
Foreign exchange loss	-	-	-	-	-	-	-	652	652
Interest expense	(9,834)	(2,228)	(12,062)	(61)	(7,404)	-	(7,465)	(10,910)	(30,437)
Interest, dividend and other income	2,143	(6)	2,137	-	488	-	488	3,034	5,659
Acquisition related costs	-	-	-	-	(2,767)	-	(2,767)	(198)	(2,965)
Loss on derivative financial instruments	(1,068)	-	(1,068)	-	-	-	-	(4,776)	(5,844)
Earnings from continuing operations before income taxes	21,679	(11,648)	10,031	3,429	9,258	-	12,687	(17,211)	5,507
Loss from discontinued operations before income taxes	(1,244)	-	(1,244)	-	-	-	-	-	(1,244)
Earnings/(loss) before income taxes	$ 20,435	$ (11,648)	$ 8,786	$ 3,429	$ 9,258	$ -	$ 12,687	$ (17,211)	$ 4,263
Property, plant and equipment	$398,037	$155,507	$553,544	$188,562	$178,003	$ -	$366,565	$ -	$920,109
Intangible assets	25,863	7,088	32,951	19,565	2,753	-	22,318	-	55,269
Assets held for sale	25,847	-	25,847	-	-	-	-	-	25,847
Total assets	482,543	176,269	658,812	228,597	212,035	-	440,632	182,863	1,282,307
Capital expenditures	25,610	13,601	39,211	774	20,393	-	21,167	367	60,745
Acquisition of operating entities	-	-	-	-	100,058	-	100,058	-	100,058

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23. Segmented information (continued)

Operational segments (continued)

The majority of non-regulated energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2012 or 2011: Hydro Québec 17% (2011 - 17%), Manitoba Hydro 20% (2011 – 16%), and California PG&E 10% (2011 - 11%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

APUC 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:

	2012	2011
Revenue		
Canada	$ 83,117	$ 88,900
United States	286,770	181,817
	$ 369,887	$270,717
Property, plant and equipment		
Canada	$ 472,333	$ 474,094
United States	1,690,382	446,015
	$ 2,162,715	$ 920,109
Intangible assets		
Canada	$ 29,480	$ 25,863
United States	27,301	29,406
	$ 56,781	$ 55,269

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

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24. Financial instruments

(a) Fair value of financial instruments

2012					
	Carrying amount	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Notes receivable	$22,937	$25,476	$ -	$ -	$25,476
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	12,695	12,695	-	12,695	-
Cross-currency swap designated as a foreign exchange hedge	408	408	-	408	-
Commodity contracts for regulatory operations	147	147	-	147	-
Total derivative financial instruments	13,250	13,250		13,250	
Total financial assets	$36,187	$38,726	$ -	$13,250	$25,476
Long-term liabilities	$770,826	$785,473	$ -	$ 785,473	$ -
Convertible debentures	960	1,319	1,319	-	-
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	9,012	9,012	-	9,012	-
Cross-currency swap designated as a foreign exchange hedge	2,078	2,078	-	2,078	-
Interest rate swaps not designated as a hedge	4,778	4,778	-	4,778	-
Energy derivative contracts	287	287	-	287	-
Commodity contracts for regulated operations	1,661	1,661	-	1,661	-
Total derivative financial instruments	17,816	17,816	-	17,816	
Total financial liabilities	$789,602	$804,608	$1,319	$803,289	$ -

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24. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

	2011				
	Carrying amount	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Notes receivable	$24,534	$24,534	$ -	$ -	$24,534
Total financial assets	$24,534	$24,534	$ -	$ -	$24,534
Long-term liabilities	$332,716	$338,264	$ -	$338,264	$ -
Convertible debentures	122,297	162,195	162,195	-	-
Derivative financial instruments:					
Interest rate swaps not designated as a hedge	6,975	6,975	-	6,975	-
Energy derivative contracts	1,169	1,169	-	1,169	-
Total derivative financial instruments	8,144	8,144	-	8,144	-
Total financial liabilities	$463,157	$508,603	$162,195	$346,408	$ -

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

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

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value (a level 2 measurement) at December 31, 2012 and 2011 due to the short-term maturity of these instruments.

Notes receivable fair values have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management. Such estimate is significantly influenced by unobservable data and therefore this fair value is subject to estimation risk.

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

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24. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company's Level 2 fair value derivative instruments primarily consist of swaps, options, and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace.

The Red Lily conversion option is measured at fair value on a recurring basis using unobservable inputs (Level 3). The fair value is based on an income approach using an option pricing model that includes various inputs such as energy yield function from wind, estimated cash flows and a discount rate of 8.5%. The Company used a discount rate believed to be most relevant given the business strategy. There was no change in fair value of $nil during the years ended December 31, 2012 or 2011.

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

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2012 or 2011.

(b) Derivative instruments

Derivative instruments are recognized on the balance sheet as either assets or liabilities and measured at fair value each reporting period.

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas service territories. The Company's strategy is to minimize fluctuations in gas sales prices to regulated customers. The accounting for these derivative instruments is subject to current guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the accompanying balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 7 (v)).

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

	2012
Financial contracts: Gas swaps	3,353,420
Gas options	787,960
	4,141,380

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24. Financial instruments (continued)

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

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

	2012	2011
Regulatory assets:		
Gas swap contracts	$ 1,555	$ -
Gas option contracts	$ 106	$ -
Regulatory liabilities:		
Gas swap contracts	$ 90	$ -
Gas option contracts	$ 57	$ -

(ii) Cash flow hedges

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

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Pay floating price (per MW-hr)
196,231	May 2012 – December 2016	U.S. $66.57	AESO
1,144,045	January 2013 – December 2022	U.S. $42.81	PJM Western HUB
4,885,898	January 2013 – December 2022	U.S. $30.25	NI HUB
4,995,968	January 2013 – December 2027	U.S. $36.46	ERCORT North HUB

The effects on the Consolidated Statement of Operations of derivative financial instruments designated as cash flow hedge consist of the following:

	2012	2011
Gain on derivative instruments (ineffective portion)	$ 105	$ -

The following table summarizes changes in other comprehensive income attributable to derivative financial instruments designated as a hedge:

	2012	2011
Effective portion of cash flow hedge, gain	$ 5,214	$ -
Gain (loss) realized on cash flow hedge	(49)	-
	$ 5,165	$ -
Less noncontrolling interest	(1,572)	$ -
Change in fair value of cash flow hedge in other comprehensive income	$ 3,593	$ -

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24. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The Company expects $3,852 of unrealized gains currently in accumulated other comprehensive loss to be reclassified into net earnings within the next twelve months, as the underlying hedged transactions settle.

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

The Company periodically uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

Concurrent with its $150,000 debentures offering in December 2012, APCo entered into a cross currency swap, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. APCo designated the entire notional amount of the cross currency fixed for fixed interest rate swap and related short-term USD payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the USD accruals that are designated as, and are effective as, an economic hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in other comprehensive income) related to the net investment. A foreign currency loss of $1,669 was recorded in other comprehensive income in 2012.

(iv) Other derivatives

APCo provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Assets are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short term financial forward energy purchase contracts which are derivative instruments. In January 2011, APUC entered into electricity derivative contracts for a term ending February 2014, which are net settled fixed-for-floating swaps whereby APUC will pay a fixed price and receive the floating or indexed price on a notional quantity of 91,216 MW-hrs of energy over the remainder of the contact term at an average rate of approximately U.S. $52.89 per MW-hr. The estimated fair value of these forward energy hedge contracts at December 31, 2012 was a net liability of $286 (2011 - $1,169). These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

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24. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

For derivatives that are not designated as cash flow hedges and for the ineffective portion of gains and losses on derivatives that are accounted for a hedges, the changes in the fair value are immediately recognized in earnings. The effects on the statement of operations of derivative financial instruments not designated as hedges consist of the following:

	2012	2011
Change in unrealized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ -	$ (45)
Interest rate swaps	(2,197)	1,536
Energy derivative contracts	(825)	833
Total change in unrealized loss/(gain) on derivative financial instruments	$ (3,022)	$ 2,324
Realized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ (187)	$ 691
Interest rate swaps	2,094	2,138
Energy derivative contracts	987	691
Total realized loss on derivative financial instruments	$ 2,894	$ 3,520
Loss/(gain) on derivative financial instruments accounted for as hedges	$ (128)	$ 5,844
Ineffective portion of derivatives financial instruments accounted for as hedges	$ (105)	$ -
Loss/(gain) on derivative financial instruments	$ (233)	$ 5,844

(c) Risk management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view to mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk, liquidity risk, foreign currency risk and interest rate risk, and how the Company manages those risks.

ALGONQUIN POWER & UTILITIES CORP.

Notes to the Consolidated Financial Statements
December 31, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

24. Financial instruments (continued)

(c) Risk management (continued)

Credit risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents accounts receivable and notes receivable. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders in Canada all of which have a credit rating of A or better. The Company does not consider the risk associated with accounts receivable to be significant as over 80% of revenue from power generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Utility Services business unit which consists of water and wastewater utilities, electric utilities and gas utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of U.S. $35,688 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition the state regulators of the Company's utilities allow for a reasonable bad debt expense to be incorporated in the rates and therefore ultimately recoverable from rate payers.

As at December 31, 2012 the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2012	
	Canadian $	**US $**
Cash and cash equivalents and restricted cash	$ 20,452	$ 39,936
Other current assets	833	-
Accounts receivable	14,904	79,680
Allowance for Doubtful Accounts	-	(4,382)
Notes Receivable	20,747	2,201
	$ 56,936	$ 117,435

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24. Financial instruments (continued)

(c) Risk management (continued)

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company'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. As at December 31, 2012, in addition to cash on hand of $53,122 the Company had $224,310 available to be drawn on its senior debt facilities. The senior credit facilities contain covenants which may limit amounts available to be drawn.

The Company's liabilities mature as follows:

	Due less than 1 year	**Due 2 to 3 years**	**Due 4 to 5 years**	**Due after 5 years**	**Total**
Long term debt obligations	$ 1,768	$ 58,490	$ 14,853	$ 695,715	$ 770,826
Advances in aid of construction	591	-	-	71,626	72,217
Interest on long term debt	41,090	80,415	71,576	136,671	329,752
Accounts payable and due to related parties	36,094	-	-	-	36,094
Environmental obligation	2,433	32,152	15,232	10,045	59,862
Accrued liabilities	99,468	-	-	-	99,468
Derivative financial instruments:					
Cross- currency swap	-	-	-	2,077	2,077
Interest rate swaps	1,968	2,810	-	-	4,778
Energy derivative and commodity contracts	245	1,703	384	8,629	10,961
Capital lease payments	134	136	-	-	270
Other obligations	4,217	3,100	380	15,972	23,669
Total obligations	$188,008	$ 178,806	$102,425	$ 940,735	$1,409,974

Foreign currency risk

The Company is exposed to currency fluctuations from its U.S. based operations. APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations.

In August 2012, APCo designated the amounts drawn on its bank credit facility denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The foreign currency transaction gain or loss on the outstanding U.S. dollar denominated balance of APCo's facility that is designated a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in other comprehensive income) related to the net investment, to the extent it is effective as a hedge. A foreign currency loss of $452 was recorded in other comprehensive income.

Interest rate risk

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project specific debt and its revolving credit facility, its interest rate swaps as well as interest earned on its cash on hand. The Company does not currently hedge that risk.

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24. Financial instruments (continued)

(c) Risk management (continued)

Interest rate risk (continued)

APCo is party to an interest rate swap whereby, the Company pays a fixed interest rate of 4.47% on a notional amount of $64,276 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. At December 31, 2012, the estimated fair value of the interest rate swap was a liability of $4,778 (2011 – liability of $6,975). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

25. Subsequent event

Subsequent to year-end, effective January 1, 2013, the Company issued 100 redeemable Series C preferred shares in exchange for Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APCo and the legal owner of the St. Leon facility (note 19). Thirty six of the Class C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 have a contractual cumulative cash dividend paid quarterly based on a prescribed payment schedule out to the redemption date in 2031. Consequently, these shares will be accounted for as liabilities in the financial statements. The cumulative dividends are indexed in proportion to the increase in CPI over the term of the shares. The dividend is intended to approximate the distributions that otherwise would have accrued to holders of Class B limited partnership units.

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

The Class C preferred shares will initially be measured at its estimated fair value of $18,205 based on the present value of the expected contractual cash flows including dividends and redemption amount, discounted at a rate of 5.0%. The recognition of the initial fair value of $18,205 will result in an adjustment to equity of the shareholders of the Company as the Class B shares had a nominal carrying amount prior to the exchange. The preferred shares will be accounted for under the effective interest method, resulting in accretion of interest expense over the term of the shares. Dividend payments are recorded as a reduction of the Class C Preferred Share carrying value.

Estimated dividend and redemption payments due in the next five years and thereafter are:	
2013	$ 802
2014	1,078
2015	1,046
2016	919
2017	870
Thereafter to 2031, including redemption amount	26,706
Less amounts representing interest	(13,216)
Final redemption of Class C Preferred Shares	$ 18,205

26. Comparative figures

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

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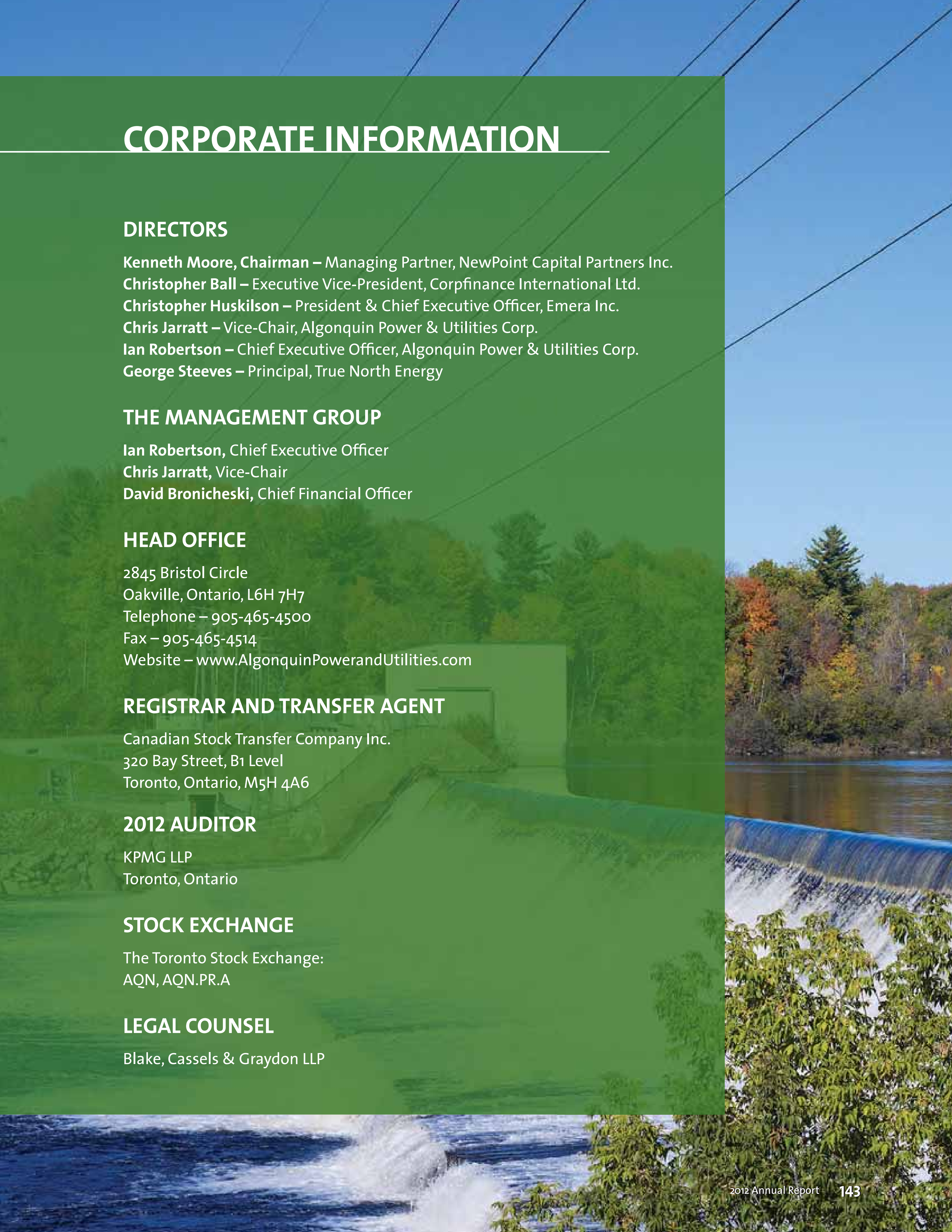

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Christopher Ball – Executive Vice-President, Corpfinance International Ltd.
Christopher Huskilson – President & Chief Executive Officer, Emera Inc.
Chris Jarratt – Vice-Chair, Algonquin Power & Utilities Corp.
Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.
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