ALGONQUIN Power & Utilities Corp.

ANNUAL REPORT 2014

Algonquin Power & Utilities is a $4.1 billion North American diversified generation, transmission and distribution utility.

Our vision is clear: To be most admired by customers, communities and investors for our people, passion and performance.

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Toronto Stock Exchange: AQN

www.AlgonquinPowerandUtilities.com

Algonquin Power & Utilities Corp.

AQN across the utility spectrum

Generation

The Generation Business Group generates and sells electricity produced by a diverse portfolio of renewable and clean energy power generation facilities across North America. We own and operate more than 35 contracted hydroelectric, wind, solar, and thermal facilities representing over 1,150 MW of installed generating capacity, and have future investment opportunities totalling over $1 billion in renewable generation to power our growth.

Algonquin Power & Utilities is an integrated utility company participating across the utility spectrum - Generation, Transmission and Distribution.

Transmission

The Transmission Business Group is a regulated transmission utility business that focuses on building and investing in natural gas pipeline and electric transmission opportunities across North America. This group serves to connect our generation and distribution businesses, completing the utility supply chain. As its inaugural project, the Transmission Business Group is partnering in a natural gas pipeline project in the north east United States, with the investment opportunity reaching $400 million by 2018.

Distribution

The Distribution Business Group owns and operates regulated water, natural gas and electricity distribution utilities in communities across the United States. We own and operate over 30 distribution utilities serving more than 488,000 customer connections across 10 states, with our focus on growth achieved through acquisitions and organic growth opportunities currently totaling $1.1 billion.

AQN by the numbers

1,275
employees

1,150
MW installed capacity

380
wind turbine generators

82,092
solar panels

76
hydroelectric generators

488,000
utility customers

10,785
km of gas distribution lines

1,920
km of electricity distribution lines

2,272
km of water distribution mains

14
year average contract length of power purchase agreements

2014 Achievements

Algonquin Power & Utilities is led by an experienced executive management team with over 65 years of combined experience in generation, transmission and distribution utilities. We have successfully grown the business for more than 20 years and now boast annual revenues of nearly $1 billion, total utility assets of more than $4 billion and a market capitalization of over $2 billion.

37% Annual total shareholder return

49% EBITDA[1] growth

14% Asset growth

50% Adjusted net earnings per share[1]

31% Cash flow per share

12% Dividend increase

2014 Financial Highlights

(in $ millions)

Revenue	2014	2013	2012
Generation Revenue	218.8	189.7	118.0
Distribution Revenue	724.8	485.2	230.8
Other	–	0.4	–
Total Revenue	**943.6**	**675.3**	**348.8**
Adjusted EBITDA[1]	**290.6**	**228.1**	**88.1**
Earnings, Funds from Operations and Dividends			
Adjusted Funds from Operations	206.5	154.9	66.8
Per Share	0.92	0.73	0.42
Adjusted Net Earnings	88.4	59.5	18.9
Per Share	0.37	0.26	0.11
Dividends to Shareholders	82.9	68.3	50.2
Per Share	0.37	0.33	0.30
Balance Sheet Data			
Total Assets	4,113.7	3,476.5	2,779.0
Long-Term Liabilities (includes current portion)	1,280.0	1,255.6	770.8
Number of Shares Outstanding as of Dec. 31	238,149,468	206,860,592	188,763,486
Renewable energy production (% of long term average)	**98%**	**95%**	**93%**
Utility Connections	**488,000**	**481,400**	**344,700**

[1]Non-GAAP Financial Measures

The terms “adjusted net earnings”, “adjusted earnings before interest, taxes, depreciation and amortization”, and “adjusted funds from operations” (together, the “Financial Measures”) are used throughout this Annual Report. The Financial Measures are not recognized measures under GAAP. There is no standardized measure of the Financial Measures, 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 these Financial Measures can be found in the Management Discussion & Analysis section of this Annual Report.

Leading in Corporate Responsibility

Our vision is to be the utility company most admired by customers, communities and investors for our people, passion and performance. We will achieve this vision through our proven growth strategy, a passionate workforce and continuing commitment to corporate responsibility. As a leader in the North American utility industry, Algonquin Power & Utilities makes a conscious effort to conduct our business practices in a socially, economically, and environmentally responsible manner.

Our commitment is deeply rooted in our business; we pride ourselves on acquiring, developing, and operating assets that create sustainable, long-term value and benefit for all of our stakeholders. These stakeholders include our customers, communities, employees, the environment, and you – our valued shareholders. Corporate Responsibility is about connecting the gap between stakeholder value and financial performance, and we will continue to grow a value-driven corporation with our stakeholders at the forefront of thought and action.

Using the Global Reporting Initiative as our framework, we are pleased to have our first Corporate Responsibility Report available electronically, accessible through our website – www.AlgonquinPowerAndUtilities.com – via the SUSTAINABILITY tab. We encourage you to visit the site and read about our sustainability efforts. Going forward, Corporate Responsibility reporting will be an annual process as we launch new initiatives and develop those already in place. Our aim is to become more comprehensive and in-depth with our reporting efforts.

Letter to Shareholders

Ian Robertson
CEO

Ken Moore
Chairman of the Board of Directors

Dear Fellow Shareholders,
The year 2014 was a year of impressive growth for Algonquin Power & Utilities, and evident from our financial results, a year of unprecedented execution and evolution as one of North America's leading utility companies. Through continued successful integration of new acquisitions as well as organic growth, the completion of several development projects, and the formation of a new business group, we continued to exceed the expectations of our investors and stakeholders.

Our vision is to be the utility company most admired by customers, communities and investors for our people, passion and performance. In order to make this vision a reality, we strive to build an organization that delivers strong shareholder value by fostering an environment well positioned for success and continued long term growth.

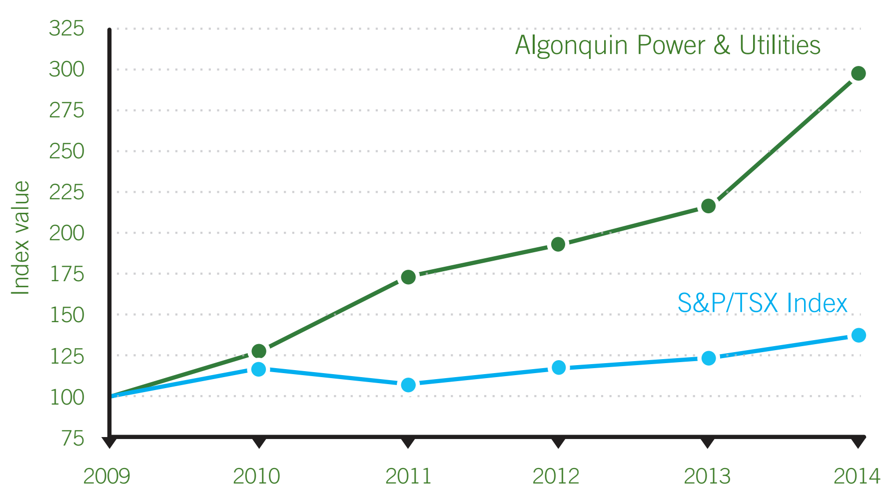
Here is how we make that happen.

People

We know that, at its root, our success stems from the significant contributions of our people. Algonquin Power & Utilities is proud to be represented by more than 1,250 employees – a number that continues to grow every day as we expand our diverse team of talented and motivated professionals. Each and every employee has played an important and valuable role in making this company what it is today.

In addition to our employees, we continue to expand the strength and diversity of our Board of Directors. This past year saw the appointment of two new members, Masheed Saidi and Dilek Samil. Ms. Saidi is a registered professional engineer with over 30 years of operational and business leadership

Total Return Performance



experience in the regulated utility industry. Ms. Samil brings over 30 years of finance, operations, and business experience in the regulated energy utility sector and generation and system operations. The strength of our Board of Directors is vital to our success through the continuation of exceptional corporate governance.

Passion

Foremost in our daily activities, it is our objective to conduct our operations in an environmentally sound and safe manner. We are proud that our 2014 safety record continues to surpass industry averages, and challenges world class performance. At Algonquin Power & Utilities we are passionate about the safety of our employees and our communities. Safety is and has always been a fundamental part of our company culture. 2014 saw the continuation of many safety-focused initiatives, including our "Drive to Zero" program, which is based on having no recordable or lost time injuries. We are pleased to note that 2014 saw continued improvement in our safety metrics, and we will continue to foster a working environment where safety is top of mind for every employee.

We are also committed to delivering attractive shareholder value consistent with our vision of being a "must own" investment holding in the portfolio of every long minded investor. We are pleased with having delivered 2014 total shareholder return of 37% and reaching an all-time adjusted EBITDA high of $291M in 2014, an increase of more than 30% over 2013. Additionally, revenue was up 40% to $943 million and our overall market capitalization grew by 52% compared to 2013.

We are equally passionate about leading an organization that operates in a socially, ethically, and environmentally responsible manner. Sustainability is deeply-rooted in our company culture, and this past year we made tremendous advancements in launching our first on-line Corporate Responsibility report. Using the Global Reporting Initiative as our compass, this annual report formally documents our operational practices measured against a sustainability reporting framework as a means of understanding and communicating the accountability of our actions. To us, a successful business is one that not only serves our shareholders, but delivers value to all stakeholders including customers, communities and employees.

Performance

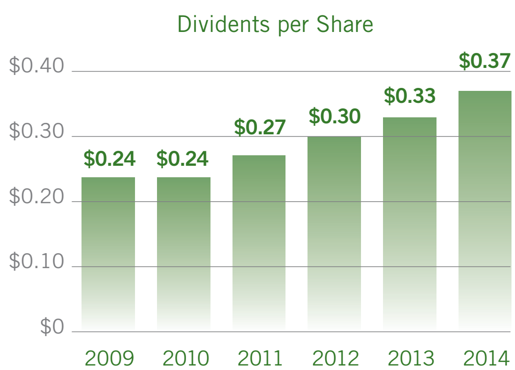
Generation

It was another active year for our Generation group, which saw the investment of over $200 million in new long term contracted renewable power projects.

As in previous years, 2014 saw the continuation of our strategic focus on growing our generation business through the development of green-field renewable power projects. We achieved commercial operation at our 24 MW St. Damase Wind Project in Quebec and our 10 MW Cornwall Solar Project in Ontario. We also made significant progress on the 24 MW Morse Wind Project

The financial success highlighted throughout this annual report confirms our ability to effectively execute on our projected financial goals and growth strategies.

Our financial success was validated by the Board of Directors' decision in August to approve a 12.4% dividend increase from CDN $0.34 to U.S. $0.35 per common share.



in Saskatchewan and our 20MW Bakersfield Solar project in Californa, with both projects being substantially constructed in 2014 and expected to reach commercial operation early in 2015. In November, we announced a further 10 MW expansion of our Bakersfield Solar Project in California, an important commitment to our growing solar portfolio.

Also in 2014, we became the sole owner of three wind projects in the United States, which added 160 MW of net generation capacity to our existing wind generation portfolio. With 100% ownership, we expect the investment to contribute accretive, low risk earnings and cash flow to our bottom line.

Additional progress was made in advancing our pipeline of development-phase projects, which is the foundation of our medium term growth. In September, we announced our commitment to the construction-stage 200 MW Odell Wind Project in Minnesota, which is scheduled to be constructed in late 2015.

Distribution

2014 saw the successful completion of our Distribution group's $175 million capital investment program into the existing portfolio of regulated distribution utilities.

We continued the expansion of our water distribution operations in the United States with the agreement to acquire Park Water Company. Park Water owns and operates three regulated water utilities in Southern California and Western Montana and its acquisition will add 74,000 connections to our existing service base of nearly half a million customers in the latter half of 2015. Through the year, we validated our ability to expand our service territory footprint with the acquisition of New Hampshire Gas, a gas distribution utility that serves more than 1,200 customers and the Whitehall water system, serving approximately 4,000 customers in Arkansas.

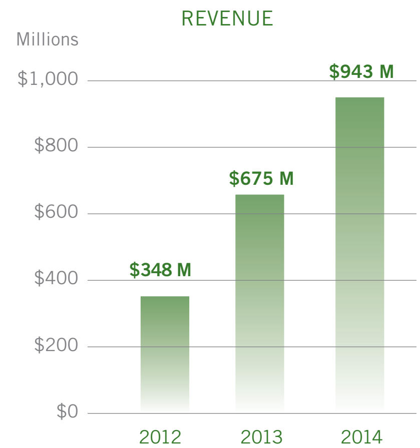
We also succeeded in finalizing a number of rate cases in our various jurisdictions, including New Hampshire, Georgia, and Arizona, which will provide over $15 million in additional revenues beginning in 2015.

The core proposition of our Distribution business group is providing local, responsive and caring service to our customers. We are committed to local decision making and priority setting in the communities in which we operate. In 2014, we reaffirmed our commitment to resource conservation, infrastructure improvements and overall customer service, and we will continue this focus into 2015 and beyond.

Transmission

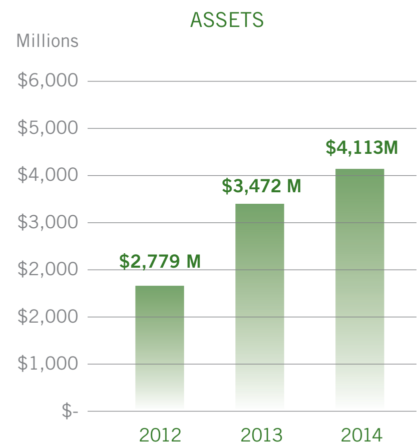
This past year marked the formal creation of our Transmission group, focused on originating and developing investment opportunities within the electrical transmission and natural gas pipeline sectors. With the launch of this new business group, Algonquin Power & Utilities is a diversified, connected utility company operating across the spectrum from generation to transmission and, ultimately, distribution.

The formation of our Transmission group was confirmed with our November announcement of a development partnership in Kinder Morgan's proposed Northeast Energy Direct natural gas pipeline project. The pipeline's resource will be contracted with local distribution utilities and other customers to ease supply constraints in the northeast United States and help ensure reliable delivery to the power-generation grid. This new pipeline not only provides a valued service and resource to the gas constrained region of the New England states, but also provides Algonquin Power & Utilities with another avenue for growth.



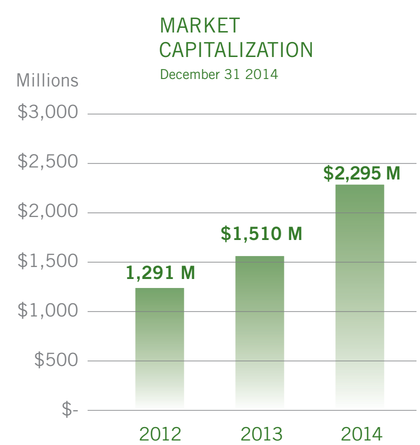
Financial Success

We believe that the financial success highlighted throughout this annual report demonstrates our ability to effectively execute on our financial goals and growth strategies. We are pleased to report that in 2014 we realized a total shareholder return of 37%. 2014 was a year of continued growth, as annual revenues grew by 40%, our asset base expanded by 18%, and our market capitalization increased 52%, as compared to 2013 results.



In 2014, we were successful in positioning the company well with respect to our 2015 capital program. Capital sourcing initiatives for 2014 saw the issuance of over $370 million in equity financings, a $100 million preferred share offering, and $200 million in 4.65% senior unsecured debentures early in the year.

Our financial success was validated by the Board of Directors' decision in August to approve a 12.4% dividend increase from CDN $0.34 to U.S. $0.35 per common share. The strategic decision to change the dividend payout to U.S. dollars aimed to assume consistency with the company's predominantly U.S.-generated cash flows.



Looking ahead

As always, we will continue to seek new opportunities and execute on our growth plans, fulfilling our commitment to create long term value for our shareholders through ongoing investments in our three business groups – Generation, Transmission, and Distribution.

For our Generation group, with commercial operation at our 20 MW Bakersfield, California solar facility and our 24 MW Morse, Saskatchewan wind project expected to be behind us shortly, 2015 will see continued commitment to growing our solar and wind generation portfolios and we will focus on advancing our existing pipeline of growth projects as well as sourcing new renewable power projects to further diversify our portfolio.

Within our Distribution group, we are expecting the completion of the Park Water acquisition in the second half of 2015 and look forward to welcoming

Park Water employees to our growing Liberty Utilities family. Additionally we will remain focused on ensuring that prudent and necessary capital investments are made to ensure the safe and reliable operation of our utilities well into the future.

Our Transmission business will be focused on moving forward with the regulatory activities associated with the Kinder Morgan pipeline venture and continuing the construction of our recently approved transmission project dedicating to serving our California electric utility. We will also focus on originating additional natural gas pipeline projects and electrical transmission investment opportunities to add to our portfolio.

As a growth focused Generation, Transmission, and Distribution utility company with over $2.7 billion in investment potential over the next few years, we will continue to deliver predictable growth.

Thank You

We would like to take this time to acknowledge and thank you, our shareholders, for your tremendous support and continued confidence in our organization. As a growth focused Generation, Transmission, and Distribution utility company with over $2.7 billion in investment potential over the next few years, we will continue to deliver predictable growth over the short, medium, and long-term. We sincerely appreciate your commitment to us and trust that 2014 has been a mutually rewarding and encouraging year. We remain devoted to creating long-term value and sector-leading returns for your investment and look forward to sharing in the successes that lie ahead.

Sincerely,

Ian Robertson
Chief Executive Officer

Ken Moore
Chairman of the Board of Directors

ALGONQUIN
Power & Utilities Corp.

Management Discussion & Analysis

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

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2014. The Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2014 and 2013. 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 15, 2015.

Caution concerning forward-looking statements and non-GAAP Measures

Forward-looking statements

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

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

Non-GAAP Financial Measures

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

Use of Non-GAAP Financial Measures

Adjusted EBITDA

EBITDA is a non-GAAP measure used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of (as applicable): depreciation and amortization expense, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, 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, earnings or loss from discontinued operations and other typically non-recurring items. 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.

Adjusted net earnings

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

Adjusted funds from operations

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

Net energy sales

Net energy sales is a non-GAAP measure used by investors to identify revenue after commodity costs used to generate revenue where revenue generally is increased or decreased in response to increases or decreases in the cost of the commodity to produce that revenue. APUC uses net energy sales to assess its revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through either directly or indirectly in the revenue that is charged. APUC believes that analysis and presentation of net energy sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Net utility sales

Net utility sales is a non-GAAP measure used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodities are generally included as a pass through in rates to its utility customers. APUC uses net utility sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by the utility customer. APUC believes that analysis and presentation of net utility sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Overview and Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC 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's current quarterly dividend to shareholders is U.S. $0.0875 per share or U.S. $0.35 per share per annum. Based on exchange rates as at December 31, 2014, the quarterly dividend is equivalent to CAD $0.10 per share or CAD $0.41 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's operations are organized across three business units consisting of Generation, Transmission and Distribution. The Generation Business Group ("Generation Group") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the recently formed Transmission Business Group ("Transmission Group") is responsible for evaluating and capitalizing upon natural gas pipeline and electric transmission asset opportunities in North America; and the Distribution Business Group ("Distribution Group") owns and operates a portfolio of North American electric, natural gas and water distribution and wastewater collection utility systems.

Generation Business Group

The Generation Group 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. The Generation Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

The Generation Group owns or has interests in hydroelectric, wind, and solar facilities with a combined generating capacity of approximately 120 MW, 675 MW, and 10MW, respectively. Approximately 83% of the electrical output from the hydroelectric, wind and solar generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 14 years.

The Generation Group owns or has interests in thermal energy facilities with approximately 335 MW of installed generating capacity. Approximately 91% of the electrical output from the owned thermal facilities is sold pursuant to long term power purchase agreements ("PPA") with major utilities, which have a weighted average remaining contract life of 7 years.

The Generation Group also has a portfolio of development projects that between 2015 and 2018 will add approximately 529 MW of generation capacity from wind and solar powered generating stations with an average contract life of 22 years.

Distribution Business Group

The Distribution Group operates diversified rate regulated electricity, natural gas, water distribution and wastewater collection utility services to approximately 488,000 connections. The Distribution Group 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, the Distribution Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

The Distribution Group's regulated electrical distribution utility systems and related generation assets are located in the States of California and New Hampshire; and together serve approximately 93,000 electric connections.

The Distribution Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, Missouri and New Hampshire; and together serve approximately 292,000 natural gas connections.

The Distribution Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, Illinois, Missouri, and Texas; and together serve approximately 103,000 connections.

Transmission Business Group

In 2014, APUC created a Transmission Group that is responsible for identifying, evaluating and capitalizing upon natural gas pipeline and electric transmission investment opportunities in North America. The Company believes that the creation of the Transmission Group complements the growth of both the Generation and Distribution Groups.

Major Highlights

2014 Corporate Highlights

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

APUC has completed several acquisitions and advanced on other initiatives including its power development projects 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 14, 2014, the Board approved a dividend increase to U.S. $0.35 per share per annum, paid quarterly at a rate of U.S. $0.0875 per share per annum, a 12.4% increase over the previous dividend of CDN $0.34 calculated using the exchange rate in effect at that time. The change in the currency of the dividend better aligns APUC's dividend with the currency profile of its underlying operations. APUC's consolidated assets are approximately 80% based in the U.S. and generate approximately 77% of its underlying cash flows.

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

Strengthening the Balance Sheet and Poising for Continued Growth

Issuance of $100 million Preferred Shares

On March 5, 2014, APUC issued 4.0 million cumulative rate reset preferred shares, Series D at a price of $25 per share, for aggregate gross proceeds of $100.0 million. The Series D shares will yield 5.0% annually for the initial five-year period ending March 31, 2019. The preferred shares have been assigned a rating of P-3 (High) and Pfd-3 (Low) by S&P and DBRS, respectively. The net proceeds of the offering were used to partially finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's revolving credit facilities, and for general corporate purposes.

Issuance of Common Shares

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

On December 11, 2014, APUC completed a public offering of 10,055,000 common shares at a price of $9.95 per share, for gross proceeds of approximately $100.0 million.

Net proceeds of both common share offerings were used to finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's revolving credit facilities, and for general corporate purposes.

Private Placement of Subscription Receipts to Emera Inc.

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

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

On December 2, 2014, APUC and Emera entered into an additional subscription agreement to which Emera agreed to subscribe for an aggregate of 3,316,583 Subscription Receipts at a price of $9.95 per Subscription Receipt, for a subscription price of $33.0 million.

The proceeds of the Subscription Receipts private placements are intended to be used to partially finance the acquisitions of the Odell Wind Project and the Park Water Facility (described below).

2014 Generation Group Highlights

Acquisition of Odell Wind Project

On September 4, 2014, the Generation Group announced an opportunity to acquire an interest in the Odell Wind Project, of Minnesota. The Odell Wind Project is a 200 MW wind development located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota and is being constructed on approximately 23,000 acres of leased land. The project will utilize 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year PPA, all energy, capacity and renewable energy credits from the project will be sold to Northern States Power Company, a subsidiary of Xcel Energy Inc., which is a diversified utility operating in the Midwest U.S. Construction is expected to begin in the second quarter of 2015, with total costs estimated at U.S. $322.8 million. It is anticipated that the Odell Project will qualify for U.S. federal production tax credits having satisfied the Internal Revenue Service 5% beginning of construction investment safe-harbor guidance. Accordingly, approximately 60% of the permanent project financing is expected to be funded by tax equity investors.

The Generation Group's participation in the project will be via a 50% equity interest in a new joint venture with a third party developer. The Company is accounting for the joint venture as an equity method investment since both partners have joint control of the new venture. The Generation Group holds an option to acquire the other 50% interest on commencement of operations, which is expected in late 2015 or early 2016.

Completion of Cornwall Solar Project

During the quarter ended March 31, 2014, the Generation Group completed the construction of its 10 MWac solar project located near Cornwall, Ontario. The facility reached commercial operation on March 27, 2014 for a total capital cost of approximately $47.6 million. The facility represents the first solar project in the Generation Group's portfolio. The facility is expected to generate approximately 14,400 MW-hrs of electricity annually with the power sold under a 20 year FIT PPA with the Ontario Power Authority.

Completion of St. Damase Wind Project

On December 2, 2014, the first phase of the wind facility located in the local municipality of St. Damase reached commercial operations. The 24 MW facility is expected to generate 76,900 MW-hrs of electricity annually with the power sold under a 20 year PPA with Hydro Quebec.

It is expected that the turbines and other components utilized in the first 24 MW phase of the St. Damase Wind Project will qualify as Canadian Renewable and Conservation Expense ("CRCE"), and therefore a significant portion of the Phase I capital cost will be eligible for a refundable Quebec tax credit ("Quebec CRCE Tax Credit"). The estimated value of the Quebec CRCE tax credit for the St. Damase project is expected to be approximately $16.6 million. Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting, and entering into appropriate energy sales arrangements.

Significant Progress on Power Development Projects

During 2014, the Generation Group made significant progress advancing several of its development projects. Construction on the Bakersfield I Solar Project near Bakersfield, California began in the second quarter of 2014 and was placed in service on December 30, 2014. Final construction efforts continue with the project expected to reach full commercial operations in the first quarter of 2015.

Construction of the Morse Wind Project near Morse, Saskatchewan is in its final stages. Installation of access roads and foundations are complete, turbine delivery commenced in January 2015, and seven of ten turbines have been erected. The project is expected to be operational by March 31, 2015.

Expansion of Bakersfield I Solar Project

On November 24, 2014, APUC announced that it intends to proceed with a 10 MW project adjacent to its 20MW Bakersfield I Solar project in Kern County, California, which is currently under construction.

The 10MW Bakersfield II Solar project executed a 20 year PPA on September 22, 2014 with a large California based electric utility. The project will be located on 64 acres of land adjacent to the 20MW Bakersfield I Solar project. Construction of Bakersfield I Solar is nearing completion, with commercial operations expected to occur in the first quarter of 2015.

The total project cost for Bakersfield II Solar of approximately U.S. $27.0 million will be funded with a combination of senior debt, common equity, and contributions from tax equity investors. Consistent with financing structures utilized for U.S. based renewable energy projects including Bakersfield I Solar, it is anticipated that Bakersfield II Solar will source financing in the amount of approximately 40% of the capital costs from certain tax equity investors.

Acquisition of the Remaining 40% of a 400 MW Wind Power Portfolio

On March 31, 2014, the Generation Group acquired from Gamesa Wind US, LLC ("Gamesa") the remaining 40% of the Class B partnership units of the entity which owns a three facility 400 MW wind power portfolio (the "U.S. Wind Portfolio") in the United States for total consideration of approximately U.S. $115.0 million. As a result of the transaction, the Generation Group now owns 100% of the Class B partnership units of the entity that owns the U.S. Wind Portfolio.

The Generation Group originally acquired 60% of the Class B units of the entity which owns the U.S. Wind Portfolio in 2012. The U.S. Wind Portfolio is a 400 MW wind portfolio consisting of three facilities: Minonk (200MW), Senate (150MW), and Sandy Ridge (50MW) located in the states of Illinois, Texas, and Pennsylvania, respectively. Gamesa will continue to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities under 20 year contracts.

$200 million Senior Unsecured Debentures

On January 17, 2014, the Generation Group issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "Generation Group Debentures") pursuant to a private placement in Canada and the United States. The Generation Group Debentures were sold at a price of $99.864 per $100.00 principal amount resulting in an effective yield of 4.67%. Concurrent with the offering, the Generation Group entered into a fixed for fixed cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of approximately 4.77%.

Net proceeds were used towards financing the acquisition of the remaining 40% ownership interest in its U.S. Wind Portfolio, to reduce amounts outstanding on project debt related to its Shady Oaks Wind Facility, to reduce amounts outstanding under the Generation Group's senior unsecured revolving credit facility ("Generation Credit Facility"), and for general corporate purposes.

Additional Liquidity

On July 31, 2014, the Generation Group increased the credit available under the Generation Credit Facility to $350 million from $200 million. The larger credit facility will be used to provide additional liquidity in support of the group's $1,225.0 million development portfolio to be completed over the next three years. In addition to the larger size, the maturity of the facility has been extended from three to four years and now extends until July 31, 2018.

2014 Distribution Group Highlights

Agreement to acquire Park Water System

On September 19, 2014, the Distribution Group announced the entering into an agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure, to acquire the regulated water distribution utility Park Water Company ("Park Water System"). Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. The three utilities collectively serve approximately 74,000 customer connections and have more than 1,000 miles of distribution mains.

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

Acquisition of White Hall Water System

On May 30, 2014, the Distribution Group acquired the assets of the White Hall Water System, a regulated water distribution and wastewater treatment utility located in White Hall, Arkansas. The White Hall Water System serves approximately 1,900 water distribution and 2,400 wastewater treatment customers. Total purchase price for the White Hall Water System assets, adjusted for certain working capital and other closing adjustments, is approximately U.S. $4.5 million.

Acquisition of New Hampshire Gas

On January 2, 2015, the Distribution Group completed the acquisition of New Hampshire Gas, a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System services approximately 1,200 propane gas distribution customers. Total purchase price for the New Hampshire Gas System is approximately U.S. $3.0 million, subject to certain closing adjustments.

Successful Rate Case Outcomes

A core strategy of the Distribution Group is to ensure appropriate return on the rate base at its various utility systems. The group has successfully completed several rate cases throughout 2014, representing a cumulative annual revenue increase of approximately U.S. $29.1 million. The full annualized impact of these rate cases will be realized in 2015. Further detail on the various regulatory proceedings of the Distribution Group can be found under Regulatory Proceedings.

2014 Transmission Group Highlights

Agreement to acquire interest in Natural Gas Transmission Pipeline

On November 24, 2014, APUC announced its agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan, Inc. Specifically, Kinder Morgan Operating L.P. "A," a wholly owned subsidiary of Kinder Morgan, Inc., and Liberty Utilities (Pipeline & Transmission) Corp., a wholly owned subsidiary of APUC, have agreed to form a new entity ("Northeast Expansion LLC") to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas transmission pipeline to be located between Wright, New York and Dracut, Massachusetts(the "Project"), which will be operated by Tennessee Gas Pipeline Company, L.L.C. ("Tennessee") . The Project is scalable up to 2.2 billion cubic feet per day (Bcf/d), and the pipeline capacity will be contracted with local distribution utilities, and other customers, to help ease constraints on natural gas supply in the northeast U.S. and help ensure much needed reliability to the power-generation grid. It is anticipated that Tennessee will receive a FERC certificate in the fourth quarter of 2016, with commercial operations occurring by late 2018.

Under the agreement, APUC will initially subscribe for a 2.5% interest in Northeast Expansion LLC with an opportunity to increase its participation up to 10%. The total capital investment opportunity for APUC could be up to U.S. $400 million, depending on the final pipeline configuration and design capacity.

2014 Annual Results From Operations

As outlined, APUC has continued to advance growth initiatives throughout 2014 that had a positive contribution to the annual results. In addition, the results now reflect full year operations from the gas and water systems acquisitions completed by the Distribution Group in 2013.

Key Selected Annual Financial Information

	Year ended December 31		
(all dollar amounts in $ millions except per share information)	2014	2013	2012
Revenue	**$ 943.6**	$ 675.3	$ 348.8
Adjusted EBITDA [1]	**290.6**	228.1	88.1
Cash provided by operating activities	**192.7**	98.9	63.0
Adjusted funds from operations[1]	**206.5**	154.9	66.8
Net earnings attributable to Shareholders from continuing operations	**77.8**	62.3	13.5
Net earnings attributable to Shareholders	**75.7**	20.3	14.5
Adjusted net earnings [1]	**88.4**	59.5	18.9
Dividends declared to Common Shareholders	**82.9**	68.3	50.2
Weighted Average number of common shares outstanding	**213,953,870**	204,350,689	158,304,340
Per share			
Basic net earnings from continuing operations	**$ 0.32**	$ 0.28	$ 0.08
Basic net earnings	**$ 0.31**	$ 0.07	$ 0.09
Adjusted net earnings [1, 2]	**$ 0.37**	$ 0.26	$ 0.11
Diluted net earnings	**$ 0.31**	$ 0.07	$ 0.09
Cash provided by operating activities [1, 2]	**$ 0.90**	$ 0.48	$ 0.40
Adjusted funds from operations[1, 2]	**$ 0.92**	$ 0.73	$ 0.42
Dividends declared to Common Shareholders	**$ 0.37**	$ 0.33	$ 0.30
Total assets	**4,113.7**	3,476.5	2,779.0
Long term liabilities [3]	**1,280.0**	1,255.6	770.8

1 Non-GAAP Financial Measures

2 APUC uses per share adjusted net earnings, cash provided by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.

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

For the year ended December 31, 2014, APUC experienced an average U.S. exchange rate of approximately $1.1049 as compared to $1.0300 in the same period in 2013. 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, 2014, APUC reported total revenue of $943.6 million as compared to $675.3 million during the same period in 2013, an increase of $268.3 million or 39.7%. The major factors resulting in the increase in APUC revenue for the year ended December 31, 2014 as compared to the corresponding period in 2013 are set out as follows:

(all dollar amounts in $ millions)	Year to date December 31, 2014
Comparative Prior Period Revenue	$ 675.3
Significant Changes:	
Generation Group	
Renewable:	
Increased wind resources net of hedge settlements at the Minonk, Senate, and Sandy Ridge Wind Facilities	1.1
Higher realized prices from Renewable Energy Credits generated from the U.S. Wind Facilities	4.8
Start of commercial operations of the Cornwall Solar Facility	5.5
Increased customer load in the Maritime region	1.7
Thermal:	
Increased average prices at the Windsor Locks and Sanger Thermal Facilities	5.3
Increased sale of Renewable Energy Credits generated at the Windsor Locks Thermal Facility	0.7
Distribution Group	
Natural Gas Systems - Increased revenue due to acquisition of the Peach State Gas System (U.S. $32.9 million), and the New England Gas System (U.S. $76.3 million)	108.2
Natural Gas Systems - Revenue increase due to higher customer demand as a result of colder than average weather at the EnergyNorth and Midstates Natural Gas Systems	35.2
Electric Systems - Revenue increase at the electric systems predominantly due to higher customer demand at the Granite State Electric System	13.8
Rate Cases – Revenue increase due to higher electricity rates at the Granite State Electric System (U.S. $11.8 million) and Peach State Gas System (U.S. $5.5 million)	17.2
Water and Waste Systems – Revenue increase due to the increased customer demand	3.5
Increase due to acquisition of New England Gas System's water heater rental service (U.S. $2.8 million) and increased revenues at Peach State Gas System's Fort Benning operation (U.S. $1.0 million)	3.8
Impact of the stronger U.S. dollar	68.4
Other	(0.9)
Current Period Revenue	$ 943.6

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

Adjusted EBITDA in the year ended December 31, 2014 totalled $290.6 million as compared to $228.1 million during the same period in 2013, an increase of $62.5 million or 27.4%. The increase in Adjusted EBITDA was primarily due to acquisitions completed in 2014 and 2013, impact of rate case settlements, increased customer demand for Gas distribution, and the increase in REC transactions. 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, 2014, net earnings from continuing operations attributable to Shareholders totalled $77.8 million as compared to $62.3 million during the same period in 2013, an increase of $15.5 million. The increase was due to $63.7 million in increased earnings from operating facilities, $0.5 million in increased foreign exchange gains, and $1.2 million due to a gain on sale of assets, as compared to the same period in 2013. These items were partially offset by $18.0 million in increased depreciation and amortization expenses, $11.2 million in increased administration charges, $9.0 million in increased interest expense, $0.4 million in increased acquisition costs, $8.5 million in increased write-downs on notes receivable and property, plant, and equipment, $6.6 million in increased loss from derivative instruments, $11.4 million in increased allocations of earnings to non-controlling interests, and $7.7 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses),* as compared to the same period in 2013.

For the year ended December 31, 2014, net earnings (including discontinued operations) attributable to Shareholders totalled $75.7 million as compared to $20.3 million during the same period in 2013, an increase of $55.4 million. Net earnings per share totalled $0.31 for the year ended December 31, 2014, as compared to $0.07 during the same period in 2013.

During the year ended December 31, 2014, cash provided by operating activities totalled $192.7 million or $0.90 per share as compared to cash provided by operating activities of $98.9 million, or $0.48 per share during the same period in 2013. During the year ended December 31, 2014, adjusted funds from operations, a non-GAAP measure, totalled $206.5 million or $0.92 per share as compared to adjusted funds from operations of $154.9 million, or $0.73 per share during the same period in 2013, an increase of $51.6 million.

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

2014 Fourth Quarter Results From Operations

Key Selected Fourth Quarter Financial Information

	Three months ended December 31	
(all dollar amounts in $ millions except per share information)	**2014**	**2013**
Revenue	**$ 259.3**	$ 205.3
Adjusted EBITDA [1]	**84.3**	68.5
Cash provided by operating activities	**96.5**	28.4
Adjusted funds from operations[1]	**65.9**	46.0
Net earnings attributable to Shareholders from continuing operations	**33.1**	19.8
Net earnings attributable to Shareholders	**31.6**	13.2
Adjusted net earnings[1]	**35.2**	18.8
Dividends declared to Common Shareholders	**25.4**	17.6
Weighted Average number of common shares outstanding	**230,664,583**	206,219,121
Per share		
Basic net earnings/(loss) from continuing operations	**$ 0.13**	$ 0.09
Basic net earnings/(loss)	**$ 0.13**	$ 0.06
Adjusted net earnings[1, 2,]	**$ 0.14**	$ 0.08
Diluted net earnings/(loss)	**$ 0.12**	$ 0.06
Cash provided by operating activities [1, 2,]	**$ 0.42**	$ 0.14
Adjusted funds from operations[1, 2]	**$ 0.27**	$ 0.22
Dividends declared to Common Shareholders	**$ 0.10**	$ 0.09

1 Non-GAAP Financial Measures

2 APUC uses per share adjusted net earnings, cash provided by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.

For the three months ended December 31, 2014, APUC experienced an average U.S. exchange rate of approximately $1.136 as compared to $1.050 in the same period in 2013. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the three months ended December 31, 2014, APUC reported total revenue of $259.3 million as compared to $205.3 million during the same period in 2013, an increase of $54.0 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2014 as compared to the corresponding period in 2013 are set out as follows:

(all dollar amounts in $ millions)	Quarter ended December 31, 2014
Comparative Prior Period Revenue	$ 205.3
Significant Changes:	
Generation Group	
Renewable:	
Effect of hydrology resource compared to comparable period in prior year	1.6
Increased wind resources net of hedge settlements at the Minonk, Senate, and Sandy Ridge Wind Facilities	1.2
Higher realized prices from Renewable Energy Credits generated from the U.S. Wind Facilities	1.1
Start of commercial operations of the Cornwall Solar Facility	0.7
Decreased sales due to reduced retail customer load at the Maritime region	(0.9)
Distribution Group	
Increased revenue due to acquisition of the New England Gas System	10.5
Electric Systems - Revenue increase at the electric systems predominantly due to higher customer demand at the Granite State Electric System	4.3
Natural Gas Systems - Revenue increase due to higher customer demand as a result of colder than average weather at the EnergyNorth, Midstates, and Peach State Natural Gas Systems	8.5
Rate Cases – Revenue increase due to higher electricity rates at the Granite State Electric System (U.S. $1.6 million) and Peach State Gas System (U.S. $2.2 million)	3.8
Water and Waste Systems – Revenue increase due to the increased customer demand	1.1
Increase due to acquisition of New England Gas System's water heater rental service (U.S. $0.8 million) and increased revenues at Peach State Gas System's Fort Benning operation (U.S. $1.0 million)	1.8
Impact of the stronger U.S. dollar	21.2
Other	(0.9)
Current Period Revenue	$ 259.3

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

Adjusted EBITDA in the three months ended December 31, 2014 totalled $84.3 million as compared to $68.5 million during the same period in 2013, an increase of $15.8 million or 23.1%. The increase in Adjusted EBITDA was primarily due to acquisitions completed in December 2013, impact of rate case settlements, increased hydrology and wind resources, and increase customer demand at the EnergyNorth and Midstates Gas Systems. 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, 2014, net earnings attributable to Shareholders from continued operations totalled $33.1 million as compared to $19.8 million during the same period in 2013, an increase of $13.3 million. The increase was due to $20.3 million in increased earnings from operating facilities, $1.5 million in decreased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)*, $0.3 million in decreased interest expense, $0.7 million due to a gain on sale of assets, and $4.9 million in increased allocation of earnings to non-controlling interests, as compared to the same period in 2013. These items were partially offset by $2.1 million in increased depreciation and amortization expenses, $5.4 million in increased administration charges, $0.4 million in decreased foreign exchange gains, $0.5 million in decreased interest and dividend income, $1.0 million in increased acquisition costs, $0.3 million in increased write-downs on notes receivable and property, plant, and equipment, and $4.7 million in decreased gains from derivative instruments.

For the three months ended December 31, 2014, net earnings (including discontinued operations) attributable to Shareholders totalled $31.6 million as compared to net earnings attributable to Shareholders of $13.2 million during the same period in 2013, an increase of $18.4 million. Net earnings per share totalled $0.13 for the three months ended December 31, 2014, as compared to net earnings per share of $0.06 during the same period in 2013.

During the three months ended December 31, 2014, cash provided by operating activities totalled $96.5 million or $0.42 per share as compared to cash provided by operating activities of $28.4 million, or $0.14 per share during the same period in 2013. During the three months ended December 31, 2014, adjusted funds from operations totalled $65.9 million or $0.27 per share as compared to adjusted funds from operations of $46.0 million, or $0.22 per share during the same period in 2013. The change in adjusted funds from operations in the three months ended December 31, 2014, is primarily due to increased earnings from operations, as compared to the same period in 2013.

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

GENERATION BUSINESS GROUP

Renewable Energy Division		Three months ended December 31			Year ended December 31	
	Long Term Average Resource	2014	2013	Long Term Average Resource	2014	2013
Performance (GW-hrs sold)						
Hydro Facilities:						
Maritime Region	45.8	38.0	37.9	177.8	146.2	203.1
Quebec Region[1]	72.8	72.3	68.1	274.9	259.4	277.7
Ontario Region[2]	33.8	38.7	39.3	139.8	144.5	90.4
Western Region	12.6	13.4	12.1	65.0	74.1	66.6
	165.0	162.4	157.4	657.5	624.2	637.8
Wind Facilities:						
St. Damase[3]	6.7	4.7	—	6.7	4.7	—
St. Leon	121.4	119.9	116.5	430.2	441.4	398.0
Red Lily[4]	24.1	23.8	22.8	88.5	87.7	79.0
Sandy Ridge	43.6	46.7	38.7	158.3	149.0	138.7
Minonk	195.8	195.4	182.8	673.3	648.5	621.8
Senate	140.0	139.0	133.8	520.4	537.6	524.5
Shady Oaks	100.4	92.2	88.7	364.0	339.9	317.1
	632.0	621.7	583.3	2,241.4	2,208.8	2,079.1
Solar Facilities:						
Cornwall	2.2	1.8	—	11.8	12.8	—
Total Performance	799.2	785.9	740.7	2,910.7	2,845.8	2,716.9

1 The Generation Group's Donnacona Hydro Facility was offline during the second half of 2014. Insurance proceeds were received to compensate for lost revenue.

2 The Generation Group's Long Sault hydro facility was offline during most of the first nine months of 2013. Insurance proceeds were received to compensate for lost revenue.

3 The St Damase Wind Facility achieved commercial operation on December 2, 2014. Long term average resource and production represent production from December 2 to December 31, 2014.

4 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.

For the twelve months ended December 31, 2014, the Renewable Energy Division generated 2,845.8 GW-hrs of electricity. This level of production represents sufficient energy to supply the equivalent of 210,800 homes on an annualized basis with renewable power. As a result of renewable energy production, the equivalent of 2,086,900 tons of CO_2 gas was prevented from entering the atmosphere.

(all dollar amounts in $ millions)	Three months ended December 31 2014		Three months ended December 31 2013		Year ended December 31 2014		Year ended December 31 2013
Revenue[1]							
Hydro Sales	$	16.8	$	15.9	$	65.1	$ 61.9
Wind		26.9		24.5		88.8	83.8
Solar		0.7		—		5.5	—
Total Revenue	**$**	**44.4**	$	40.4	**$**	**159.4**	$ 145.7
Less:							
Cost of Sales - Energy[2]		(1.5)		(3.8)		(16.7)	(8.7)
Realized gain/(loss) on hedges[3]		(0.2)		0.3		3.6	0.5
Net Energy Sales	**$**	**42.7**	$	36.9	**$**	**146.3**	$ 137.5
Renewable Energy Credits ("REC")[4]		4.0		2.6		11.7	5.9
Other Revenue		0.4		0.2		1.6	1.2
Total Net Revenue	**$**	**47.1**	$	39.7	$	159.6	$ 144.6
Expenses & Other Income							
Operating expenses		(11.0)		(11.2)		(46.1)	(40.3)
Interest and Other income		0.4		0.5		1.7	1.9
HLBV income/(loss)		8.9		6.8		27.2	20.4
Divisional operating profit	**$**	**45.4**	$	35.8	**$**	**142.4**	$ 126.6

1 While most of the Generation Group'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.

2 Cost of Sales - Energy consists of energy purchases in the Maritime Region to manage the energy sales from the Tinker Facility which is sold to retail and industrial customers under multi-year contracts.

3 See financial statements note 25(b)(iv).

4 Qualifying renewable energy projects receive Renewable Energy Credits (RECs) for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source. The RECs can be traded and the owner of the REC can claim to have purchases of renewable energy. REC revenue is recognized only at the time a generated REC unit is matched up with a previously signed REC sales contract with a third party. Generated REC units not immediately available to match against a signed contract are recorded as inventory with the offset recorded as a decrease in operating expenses.

2014 Fourth Quarter Operating Results

For the three months ended December 31, 2014, the hydro facilities generated 162.4 GW-hrs of electricity, as compared to 157.4 GW-hrs produced in the same period in 2013, an increase of 3.2%. The increased generation is largely attributable to significantly better hydrology in Quebec that more than offset the Donnacona Hydro Facility being offline throughout the quarter. See the "Quebec Dam Safety Act" section for a further discussion on the Donnacona Hydro Facility.

During the three months ended December 31, 2014, the hydro facilities generated electricity equal to 98.4% of long-term projected average resources as compared to 95.2% during the same period in 2013. During the three months ended December 31, 2014, the Ontario and Western Hydro regions achieved production greater than their long-term averages. The Quebec region was below the long term average due to Donnacona being offline. Excluding Donnacona, the Quebec region would have achieved 108% of the LTAR.

For the three months ended December 31, 2014, revenue from the hydro facilities totalled $16.8 million as compared to $15.9 million during the same period in 2013, an increase of $0.9 million. Revenue from generation at the hydro facilities located in the Quebec region increased by $1.4 million, as compared to the same period in 2013. The increase is attributed to more favorable hydrology in the Quebec region. This was offset by decreased revenues in the Maritime region of $0.7 million, primarily due to decreased customer load served. Revenue in the Maritime region primarily consists of the sale of the off-take from the Tinker Hydro Facility through wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine, merchant sales of production in excess of committed customer deliveries from the Tinker Hydro Facility, and other revenue.

For the three months ended December 31, 2014, energy purchase costs at the Maritime region totalled $1.5 million, as compared to $3.8 million during the same period in 2013, a decrease of $2.3 million. The decrease in the energy purchase costs for the three months ended December 31, 2014 were primarily due to decreased retail customer load served in the quarter requiring reduced energy purchases from the market as the Maritime region was able to generate sufficient energy to meet its retail demand. During this period, approximately 21.4 GW-hrs of energy was purchased at market and fixed rates averaging U.S. $61 per MW-hr.

During the three months ended December 31, 2014, the Maritime region generated approximately 69% of the load required to service its customers, as compared to 44% in the same period in 2013. To mitigate the risk of higher average energy prices, certain power hedges are entered into as part of risk mitigation strategies. For the three months ended December 31, 2014, $0.2 million was realized in connection with these hedges and is recorded as a realized gain on derivative financial instruments in the financial statements.

For the three months ended December 31, 2014, the wind facilities produced 621.7 GW-hrs of electricity, as compared to 583.3 GW-hrs produced in the same period in 2013, an increase of 6.6%. The higher generation was a result of increased wind resources at all sites and the start of production at the newest facility, the St. Damase Wind Facility, which achieved COD on December 2, 2014. The St. Damase wind facility generated 4.7 GW-hrs.

During the three months ended December 31, 2014, the wind facilities (excluding the St. Damase Wind Facility) generated electricity equal to 98.4% of long-term projected average resources, as compared to 93.3% during the same period in 2013, due to variability in the wind resource.

For the three months ended December 31, 2014, revenue from the wind facilities totalled $26.9 million as compared to $24.5 million during the same period in 2013, an increase of $2.4 million. Revenue increases were evident at all wind facilities due mainly to the 38.4 GW/h increase in production due to an increase in wind resources, as compared to the same period last year. As a result, revenues from the Generation Group's Canadian wind facilities increased $0.8 million, while the U.S. wind facilities increased $1.9 million, as compared to the same period last year. These gains were partly offset by $0.3 million in hedge settlements under the Minonk, Senate and Sandy Ridge Wind Facilities' power hedges.

For the three months ended December 31, 2014, REC revenue totalled $4.0 million, as compared to $2.6 million in the same period in 2013, an increase of $1.4 million, primarily attributed to increased market pricing in all regions with the PJM region having the largest impact. The increase in market pricing is largely caused by the annually increasing renewable requirement of the RPS (Renewable Portfolio Standard) outpacing the increase in supply of available RECs. REC units are generated at a ratio of one REC unit per one MW-hr generated and are sold in the market in which the REC is generated. For the three months ended December 31, 2014, REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities.

During the three months ended December 31, 2014, the Generation Group's solar facility located in Ontario had its third full quarter of operations generating 1.8 GW-hrs of electricity, which is equal to 18.2% below long-term average resources. The facility reached commercial operation on March 27, 2014 and has a 20 year FIT PPA with the Ontario Power Authority.

Revenue from generation at the Generation Group's new solar facility located in Cornwall, Ontario totalled $0.7 million for the period. As commercial operation was achieved late in the first quarter of 2014, there is no comparative data from the previous year.

For the three months ended December 31, 2014, operating expenses excluding energy purchases totalled $11.0 million, as compared to $11.2 million during the same period in 2013, a decrease of $0.2 million. The decrease was primarily attributable to greater inventorying of REC costs at the Senate Wind facility partly offset by operating costs at the new Cornwall Solar Facility.

The Red Lily I Wind Facility located in Saskatchewan produced 23.8 GW-hrs of electricity for the three months ended December 31, 2014. The Generation Group's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges and is not reflected in revenue from energy sales. Under the terms of the agreements, the Generation Group has the right to exchange these contractual and debt interests in the Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the three months ended December 31, 2014, the Generation Group earned fees of $0.3 million (which is classified as other revenue) and interest income of $0.4 million from the Red Lily I Wind Facility.

For the three months ended December 31, 2014, interest and other income totalled $0.4 million, consistent with the same period in 2013. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility. This amount is included as part of the Generation Group's earnings from its investment in the Red Lily I Wind Facility, as discussed above.

For the three months ended December 31, 2014, the value of net tax attributes generated amounted to an approximate HLBV income of $8.9 million, an increase of $2.1 million compared to the prior year. The increase was attributable to increased production, a stronger U.S. dollar exchange rate, and the reduced economic interest in the projects attributable to tax equity.

For the three months ended December 31, 2014, the Renewable Energy Division's operating profit totalled $45.4 million, as compared to $35.8 million during the same period in 2013, an increase of $9.6 million; $2.5 million of the increase is attributable to the stronger U.S. dollar.

2014 Twelve Month Operating Results

For the twelve months ended December 31, 2014, the hydro facilities generated 624.2 GW-hrs of electricity, as compared to 637.8 GW-hrs produced in the same period in 2013, a decrease of 2.1%. The slight decrease in generation is largely due to a decrease in production in the Maritime region due to lower hydrology in the first 3 quarters of the year, almost completely offset by an increased production in the Ontario region with the Long Sault facility return to service, which was offline for the majority of the first and second quarter of 2013.

During the twelve months ended December 31, 2014, the hydro facilities generated electricity equal to 94.9% of long-term projected average resources, as compared to 103.4% during the same period in 2013. During the twelve months ended December 31, 2014, the Ontario and Western Hydro regions achieved production above their long-term averages. The Quebec and Maritime regions were below the long term average production. Had the Quebec region's Donnacona facility been on line, the region would have achieved 102% of the long term average hydrological resource.

For the twelve months ended December 31, 2014, revenue from the hydro facilities totalled $65.1 million, as compared to $61.9 million during the same period in 2013, an increase of $3.2 million. Revenue from generation in the Ontario region increased by $0.7 million due to the Long Sault Hydro Facility being back on-line for the full year 2014. The Quebec and Western regions experienced a decrease of $0.3 million and $0.7 million, respectively. The decrease in the Quebec region is primarily due to the Donnacona Hydro Facility being offline, while the decrease in the Western region is primarily due to lower market pricing on the unhedged portion of the production. The increase in production at the Western region caused the market exposed production amount to increase 8% while the weighted average market price fell by more than 50%. Revenue from the Maritime region increased $3.5 million, primarily due to increased retail customer load served.

For the twelve months ended December 31, 2014, energy purchases totalled $16.7 million, as compared to $8.7 million during the same period in 2013, an increase of $8.0 million. Increased energy purchase costs for the twelve months ended December 31, 2014 were primarily due to lower hydrology in the Maritime region in the first half of the year, which required increased energy purchases from external suppliers at higher average prices. During this period, purchases of approximately 166.0 GW-hrs of energy at market and fixed rates averaging U.S. $91 per MW-hr were made. During the twelve months ended December 31, 2014, the Maritime region generated approximately 46% of the load required to service its customers, as compared to 67% in the same period in 2013. To mitigate the risk of higher average energy prices, the Maritime region had previously entered into certain power hedges as part of its risk mitigation strategies. For the twelve months ended December 31, 2014, $3.6 million was realized in connection with these hedges and is recorded as a realized gain on derivative financial instruments on the Consolidated Statement of Operations.

For the twelve months ended December 31, 2014, the wind facilities produced 2,208.8 GW-hrs of electricity, as compared to 2,079.1 GW-hrs produced in the same period in 2013, an increase of 6.2%. The increased generation was a result of stronger wind resources at the St. Leon, Minonk, Sandy Ridge, and Senate Wind Facility along with the St. Damase Wind Facility which achieved COD on December 2, 2014.

During the twelve months ended December 31, 2014, the wind facilities generated electricity equal to 98.5% of long-term projected average resources, as compared to 93.1% during the same period in 2013. For the twelve months ended December 31, 2014, revenue from the wind facilities totalled $88.8 million, as compared to $83.8 million during the same period in 2013, an increase of $5.0 million. The increase in revenue was due primarily to a 129.7 GW/h increase in production from stronger wind resources, as compared to the same period last year. As a result, revenues from the Generation Group's Canadian wind facilities increased $3.5 million, while the U.S. wind facilities increased $1.5 million, net of hedge settlements under the Minonk, Senate and Sandy Ridge Wind Facilities' power hedges.

For the twelve months ended December 31, 2014, REC revenue totalled $11.7 million, as compared to $5.9 million in the same period in 2013, an increase of $5.8 million, primarily a result of increased market pricing and a greater number of RECs generated and sold. REC units are generated at a ratio of one REC unit per one MW-hr generated and are sold in the market in which the REC is generated. For the twelve months ended December 31, 2014, REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities.

During the twelve months ended December 31, 2014, the Generation Group's solar facility located in Ontario generated 12.8 GW-hrs of electricity, which is equal to 8.5% above long-term average resources from the commercial operation date. The facility reached commercial operation on March 27, 2014 and has a 20 year FIT PPA with the Ontario Power Authority.

Revenue from generation totalled $5.5 million for the period. The facility achieved commercial operation on March 27, 2014 and therefore there is no comparative data from the previous year.

For the twelve months ended December 31, 2014, operating expenses excluding energy purchases totalled $46.1 million, as compared to $40.3 million during the same period in 2013, an increase of $5.8 million. The increase was due to the appreciation of the U.S. dollar, operating costs for Cornwall's first year of operations, and cost of RECs contracted in the first quarter of 2014 but produced in the fourth quarter of 2013.

For the twelve months ended December 31, 2014, interest and other income totalled $1.7 million, as compared to $1.9 million during the same period in 2013. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility. This amount is included as part of the Generation Group's earnings from its investment in Red Lily I Wind Facility, as discussed below.

The Red Lily I Wind Facility located in Saskatchewan produced 87.7 GW-hrs of electricity for the twelve months ended December 31, 2014. The Generation Group's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges and is not reflected in revenue from energy sales. Under the terms of the agreements, the Generation Group has the right to exchange these contractual and debt interests in the Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the twelve months ended December 31, 2014, the Generation Group earned fees of $1.3 million (which is classified as other revenue) and interest income of $1.6 million from the Red Lily I Wind Facility.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of net tax attributes, primarily related to electricity production generated by the Generation Group in the period from certain of its U.S. wind power generation facilities. The value of net tax attributes generated in the twelve months ended December 31, 2014 amounted to an approximate HLBV income of $27.2 million, as compared to $20.4 million in the prior year. The increase of $6.8 million was primarily a result of a stronger U.S. dollar exchange rate, increased production at all U.S. sites, and a higher income allocation to the Generation Group due to the reduced economic interest of Tax Equity investors in the projects.

For the twelve months ended December 31, 2014, the Renewable Energy Division's operating profit totalled $142.4 million, as compared to $126.6 million during the same period in 2013, an increase of $15.8 million; $3.5 million of the increase is attributable to the stronger U.S. dollar.

GENERATION BUSINESS GROUP

Thermal Energy Division	**Three months ended December 31, 2014**			**Three months ended December 31, 2013**		
	Windsor Locks	**Sanger**	**Total**	**Windsor Locks**	**Sanger**	**Total**
Performance (GW-hrs sold)	**26.3**	**35.1**	**61.4**	28.8	35.6	64.4
Performance (steam sales – billion lbs)	**157.3**	**—**	**157.3**	161.3	—	161.3
(all dollar amounts in $ millions)						
Revenue						
Energy/steam sales	$ **4.7**	$ **4.3**	$ **9.0**	$ 4.6	$ 3.9	$ 8.5
Less:						
Cost of Sales – Fuel	**(3.1)**	**(1.9)**	**(5.0)**	(3.1)	(1.5)	(4.6)
Net Energy/Steam Sales	$ **1.6**	$ **2.4**	$ **4.0**	$ 1.5	$ 2.4	$ 3.9
Other Revenue	**0.1**	**0.6**	**0.7**	0.2	0.6	0.8
Total Net Revenue	$ **1.7**	$ **3.0**	$ **4.7**	$ 1.7	$ 3.0	$ 4.7
Expenses						
Operating Expenses	$ **(0.7)**	$ **(1.3)**	$ **(2.0)**	$ (0.9)	$ (1.2)	$ (2.1)
Facility operating profit	$ **1.0**	$ **1.7**	$ **2.7**	$ 0.8	$ 1.8	$ 2.6
Interest and other income			**(0.3)**			0.1
Divisional operating profit			$ **2.4**			$ 2.7

2014 Fourth Quarter Operating Results

The Generation Group's Sanger and Windsor Locks Thermal Facilities purchase natural gas from different suppliers and at prices based on different regional hubs. As a result, the average landed cost per unit of natural gas will differ between the two facilities in the average landed cost for natural gas and may result in the facilities showing differing costs per unit compared to each other and compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each MMBTU.

Production data, revenue and expenses have been adjusted to remove the results of the EFW and BCI Thermal Facilities, which were divested on April 4, 2014 for proceeds approximating the carrying value of the net assets on the Consolidated Balance Sheet of the Company as at March 31, 2014. The results of the EFW and BCI Thermal Facilities for the period up to the date of sale are reported as discontinued operations. See Financial Statement note 17 for details.

For the three months ended December 31, 2014, the Thermal Energy Division's operating profit was $2.4 million, as compared to $2.7 million in the same period in 2013, a decrease of $0.3 million. Operating profit contributions for the three months ended December 31, 2014 were $1.0 million from the Windsor Locks Thermal Facility and $1.7 million from the Sanger Thermal Facility, as compared to $0.8 million and $1.8 million, respectively, during the same period in 2013. Interest and other income for the three months ended December 31, 2014 was a loss of $0.3 million, as compared to income of $0.1 million in the prior period. As a result of the stronger U.S. dollar, operating profit increased by $0.2 million.

Windsor Locks Thermal Facility

For the three months ended December 31, 2014, the Windsor Locks Thermal Facility sold 157.3 billion lbs of steam and 26.3 GW-hrs of electricity, as compared to 161.3 billion lbs of steam and 28.8 GW-hrs of electricity in the comparable period of 2013.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $4.7 million (U.S. $4.1 million), as compared to $4.6 million (U.S. $4.4 million) in the same period in 2013. The change in electricity/steam sales is attributed to lower production, but partly offset by a higher average price for gas as a result of the better ISO NE electricity market price. Gas costs for the period were $3.1 million (U.S. $2.7 million), as compared to$3.1 million (U.S. $2.9 million) in the same period in 2013. The change in gas costs is a result of decreased production, partly offset by increases in the average landed cost of natural gas per MMBTU in the quarter, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended December 31, 2014, net sales at the Windsor Locks Thermal Facility totalled $1.6 million (U.S. $1.4 million) as compared to $1.5 million (U.S. $1.5 million) in the same period in 2013. This variance was driven by a small increase in revenue, which was largely the result of the stronger US dollar, and a small decrease in gas costs.

Operating expenses excluding fuel costs were $0.7 million (U.S. $0.6 million), as compared to $0.9 million (U.S. $0.8 million) in the same period in 2013. The decrease was primarily due to an increase in inventorying of REC costs vs the same period last year. Generated RECs that have not been sold under a customer contract are recorded as an increase to inventory with an offset booked to operating expense. The Windsor Locks Thermal Facility's resulting net operating income for the three months ended December 31, 2014 was $1.0 million (U.S. $0.9 million), as compared to $0.8 million (U.S. $0.9 million) in the same period in 2013; $0.2 million of the increase is attributable to the stronger U.S. dollar.

Sanger Thermal Facility

For the three months ended December 31, 2014, the Sanger Thermal Facility sold 35.1 GW-hrs of electricity, as compared to 35.6 GW-hrs of electricity in the comparable period of 2013.

For the three months ended December 31, 2014, the Sanger Thermal Facility's operating profit was driven by energy/steam sales of $4.3 million (U.S. $3.8 million), as compared to $3.9 million (U.S. $3.7 million) in the same period in 2013, an increase of $0.4 million. The increase in energy/steam sales is primarily due to an increase in the contract basis differential and passing on higher gas prices to our customer, as compared to the same period in 2013. Capacity revenues remained unchanged at $1.7 million. Gas costs for the period were $1.9 million (U.S. $1.7 million), as compared to $1.5 million (U.S. $1.5 million) in the same period in 2013. The increase in gas costs is largely due to a an increase in the average cost of natural gas per MMBTU and a stronger U.S. dollar, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended December 31, 2014, net energy sales at the Sanger Thermal Facility totalled $2.4 million (U.S. $2.1 million), as compared to $2.4 million (U.S. $2.2 million) during the same period in 2013.

Operating expenses excluding natural gas costs were $1.3 million (U.S. $1.2 million), as compared to $1.2 million (U.S. $1.1 million) in the same period in 2013. The Sanger Thermal Facility's resulting net operating income for the three months ended December 31, 2014 was $1.7 million (U.S. $1.5 million), as compared to $1.8 million (U.S. $1.6 million) during the same period in 2013; the net U.S. dollar impact on the change in the Sanger Thermal Facility's net operating income was nil.

	Twelve months ended December 31, 2014						Twelve months ended December 31, 2013					
		Windsor Locks		Sanger		Total		Windsor Locks		Sanger		Total
Performance(GW-hrs sold)		**112.4**		**134.2**		**246.6**		115.3		137.4		252.7
Performance(steam sales – billion lbs)		**609.1**		**—**		**609.1**		623.0		—		623.0
(all dollar amounts in $ millions)												
Revenue												
Energy/steam sales	**$**	**23.1**	**$**	**19.8**	**$**	**42.9**	$	17.6	$	16.9	$	34.5
Less:												
Cost of Sales – Fuel		**(15.1)**		**(7.5)**	**$**	**(22.6)**		(11.2)		(6.0)		(17.2)
Net Energy/Steam Sales	**$**	**8.0**	**$**	**12.3**	**$**	**20.3**	**$**	**6.4**	**$**	**10.9**	**$**	**17.3**
Other revenue		**1.3**		**1.9**		**3.2**		0.5		1.9		2.4
Total net revenue	**$**	**9.3**	**$**	**14.2**	**$**	**23.5**	**$**	**6.9**	**$**	**12.8**	**$**	**19.7**
Expenses												
Operating expenses		**(4.4)**		**(5.0)**		**(9.4)**		(3.7)		(4.8)		(8.5)
Facility operating profit	**$**	**4.9**	**$**	**9.2**	**$**	**14.1**	**$**	**3.2**	**$**	**8.0**	**$**	**11.2**
Interest and other income (loss)					**$**	**(0.5)**					$	0.2
Divisional operating profit						**13.6**						11.4

2014 Twelve Month Operating Results

The Generation Group's Sanger and Windsor Locks Thermal Facilities purchase natural gas from different suppliers and at prices based on different regional hubs. As a result, the average landed cost per unit of natural gas will differ between the two facilities in the average landed cost for natural gas and may result in the facilities showing differing costs per unit compared to each other and compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each MMBTU.

Production data, revenue and expenses have been adjusted to remove the results of the EFW and BCI Thermal Facilities, which were divested on April 4, 2014 for proceeds approximating the carrying value of the net assets on the Consolidated Balance Sheet of the Company as at March 31, 2014. The results of the EFW and BCI Thermal Facilities for the period up to the date of sale are reported as discontinued operations. See Financial Statement note 17 for details.

For the twelve months ended December 31, 2014, the Thermal Energy Division's operating profit was $13.6 million, as compared to $11.4 million in the same period in 2013, an increase of $2.2 million. The Windsor Locks Thermal Facility contributed $4.9 million, while the Sanger Thermal Facility contributed $9.2 million of operating profit during the twelve months ended December 31, 2014, as compared to $3.2 million and $8.0 million, respectively, during the same period in the prior year. Interest and other income for the twelve months ended December 31, 2014 was a loss of $0.5 million, as compared to income of $0.2 million during the same period in the prior year. As a result of the stronger U.S. dollar, operating profit was positively impacted by $1.1 million.

Windsor Locks Thermal Facility

For the twelve months ended December 31, 2014, the Windsor Locks Thermal Facility sold 609.1 billion lbs of steam and 112.4 GW-hrs of electricity, as compared to 623.0 billion lbs of steam and 115.3 GW-hrs of electricity in the comparable period of 2013.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $23.1 million (U.S. $20.9 million), as compared to $17.6 million (U.S. $17.1 million) in the same period in 2013. The increase in electricity/steam sales is attributed to a higher average price for gas as a result of the better ISO NE electricity market price driven by seasonally low temperatures in the first half of 2014. Gas costs for the period were $15.1 million (U.S. $13.7 million), as compared to

$11.2 million (U.S. $10.9 million) in the same period in 2013. The increase in gas costs is a result of increases in the average landed cost of natural gas per MMBTU in the first three quarters of the year, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the twelve months ended December 31, 2014, net energy/steam sales at the Windsor Locks Thermal Facility totalled $8.0 million (U.S. $7.2 million), as compared to $6.4 million (U.S. $6.2 million) during the same period in 2013, an increase of $1.6 million (U.S. $1.0 million).

Operating expenses excluding natural gas costs were $4.4 million (U.S. $4.0 million), as compared to $3.7 million (U.S. $3.6 million) during the same period in 2013. The increase is primarily attributable to a stronger U.S. dollar and the cost of RECs sold in the first nine months of 2014 but generated in 2013 (an offset to operating expense is booked when a REC is generated and is recorded as inventory). The Windsor Locks Thermal Facility's resulting net operating income for the twelve months ended December 31, 2014 was $4.9 million (U.S. $4.4 million), as compared to $3.2 million (U.S. $3.1 million) in the same period in 2013, an increase of $1.7 million; $0.4 million of the increase is attributable to the stronger U.S. dollar.

Sanger Thermal Facility

For the twelve months ended December 31, 2014, the Sanger Thermal Facility sold 134.2 GW-hrs of electricity, as compared to 137.4 GW-hrs of electricity in the comparable period of 2013. The decrease in production is due to the Sanger Thermal Facility's planned outage and limitation of run hours in the first quarter of 2014.

For the twelve months ended December 31, 2014, the Sanger Thermal Facility's operating profit was driven by energy/steam sales of $19.8 million (U.S. $17.9 million), as compared to $16.9 million (U.S. $16.4 million) in the same period in 2013, an increase of $2.9 million. The increase in energy/steam sales is attributed primarily to increased gas prices, as compared to 2013, which is a pass through to customers. Capacity revenues remained unchanged at $8.4 million. Gas costs for the period were $7.5 million (U.S. $6.8 million), as compared to $6.0 million (U.S. $5.8 million) in the same period in 2013. The increase in gas costs is largely due to a 19% increase in the average cost of natural gas per MMBTU and a stronger U.S. dollar, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the twelve months ended December 31, 2014, net energy sales at the Sanger Thermal Facility totalled $12.3 million (U.S. $11.1 million), as compared to $10.9 million (U.S. $10.6 million) during the same period in 2013, an increase of $1.4 million primarily due to more favorable pricing on the variable portion of the supply contract and an increase in the U.S. dollar exchange rate.

Operating expenses excluding natural gas costs were $5.0 million (U.S. $4.5 million), as compared to $4.8 million (U.S. $4.7 million) during the same period in 2013. The Sanger Thermal Facility's resulting net operating income for the twelve months ended December 31, 2014 was $9.2 million (U.S. $8.3 million), as compared to $8.0 million (U.S. $7.8 million) in the same period in 2013, an increase of $1.2 million; $0.7 million of the increase is attributable to the stronger U.S. dollar.

GENERATION BUSINESS GROUP

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 the Generation Group'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. The Generation Group'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 PPA, obtaining the required financing commitments to develop the project, completion of environmental and other required 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 the Generation Group's Development Division will begin construction or execute an acquisition agreement.

The Generation Group's Development Division has successfully completed, is constructing and is developing a number of power generation projects. The projects are as follows:

Project Name	Location	Size (MW)		Estimated Capital Cost (millions)	Commercial Operation	PPA Term	Production GW-hrs
Projects Completed							
Cornwall Solar Facility[1]	Ontario	10	$	47.6	2014	20	14.4
St. Damase Wind Facility[1]	Quebec	24	$	69.7	2014	20	76.9
Total Completed		**34**	**$**	**117.3**			**91.3**
Projects in Construction							
Morse Wind Project[1]	Saskatchewan	23	$	81.3	2015	20	104.0
Bakersfield I Solar Project[1,2]	California	20	$	67.9	2015	20	53.3
Total Project in Construction		**43**	**$**	**149.2**			**157.3**
Projects in Development							
Odell Wind Project[1,3]	Minnesota	200	$	374.5	2015/16	20	814.7
Val Eo Wind Project[1,4,5]	Quebec	24	$	70.0	2016/17	20	66.0
Bakersfield II Solar Project[1,6]	California	10	$	31.3	2016	20	26.5
Amherst Island Wind Project[1]	Ontario	75	$	260.0	2016/17	20	235.0
Chaplin Wind Project[1,7]	Saskatchewan	177	$	340.0	2017/18	25	720.0
Total Projects in Development		**486**	**$**	**1,075.8**			**1,862.2**
Total in Construction and Development		**529**	**$**	**1,225.0**			**2,019.5**

1 PPA Signed.

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

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

4 The Val Eo Wind Project is being developed in two phases: Phase I of the project (24 MW) will be erected in 2015 and the101 MW Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

5 Size, Estimated Capital Costs, Commercial Operation Date, PPA Term and Production refer solely to Phase I of the Val-Eo Wind Project.

6 Total cost of the project is expected to be approximately $27.0 million in U.S. dollars.

7 The Chaplin project is being developed in two phases: Phase I of the project , which comprises approximately 35 MW of the total project, will be erected in 2017 and Phase II of the project, which comprises the remaining approximately 142 MW, will be constructed following evaluation of the wind resource at the site, and completion of satisfactory permitting.

Projects Completed

Cornwall Solar Facility

Construction of the project is now complete and commercial operation was achieved on March 27, 2014. The Cornwall Solar Facility is anticipated to have energy production of 14.4 GW-hrs/year. The Cornwall Solar Facility has been granted a 10 MW Feed In Tariff ("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. Operating results from this project are now being reported in the Generation Group's renewable energy results.

St. Damase Wind Facility

Construction of the St. Damase Wind Facility is now complete and commercial operation was achieved on December 2, 2014. The facility has a 20 year PPA with Hydro Quebec. It is a 24 MW facility and is expected to generate $7.4 million in revenue in its first full year of operations.

It is expected that the turbines and other components utilized in the first 24 MW phase of the Saint-Damase Wind Facility will qualify as CRCE, and therefore a significant portion of the Phase I capital cost will be eligible for a refundable Quebec CRCE Tax Credit. In June 2014, the government of Quebec released the 2014-2015 budget, which included a 20% reduction in value for a wide range of tax credits, including the Quebec CRCE Tax Credit. The estimated value of the Quebec CRCE tax credit for the St. Damase project is expected to be approximately $16.6 million. Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting, and entering into appropriate energy sales arrangements. Operating results from this project are now being reported in the Generation Group's renewable energy results.

Projects in Construction

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.

Based on the award of 25 MW under Saskatchewan's Green Options Partner Program, SaskPower has offered the Generation Group a 20 year contract for the procurement of 23 MW of wind generation to match the nameplate capacity of the proposed turbines.

The Generation Group 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 the Generation Group 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 turbine supply agreements have been executed with Siemens and the Balance of Plant Engineering, Procurement and Construction agreement has been signed. The turbine placement has been finalized and registered land leases have been executed with the landowners. Installation of access roads and foundations are completed, and turbine delivery commenced in January 2015. Seven of ten turbine have been erected, and the project is expected to be operational by March 31, 2015.

Bakersfield I Solar Project

The Generation Group has entered into an agreement for the continuing development of a 20 MWac solar powered generating station located in Kern County, California. Following commissioning, the Bakersfield Solar Project is expected to generate 53.3 GW-hrs of energy per year. All energy from the project will be sold to PG&E pursuant to a 20 year agreement with expected first full year revenues of U.S. $4.7 million. The Generation Group has entered into a partnership agreement with a third party (the "Tax Partner") pursuant to which the Tax Partner will receive the majority of the tax attributes associated with the project. The Tax Partner will contribute U.S. $22.0 million to the project with the remaining of the total estimated cost of U.S. $58.5 million to be funded by the Generation Group.

Construction of the project commenced in the second quarter of 2014 and was placed in service on December 30, 2014. Testing to ensure the plant will be ready and available for commercial operations was conducted and confirmed by the Generation Group and independent engineers. Final construction efforts continue, with the project expected to reach full commercial operation in the first quarter of 2015.

Projects in Development

Odell Wind Project

The Odell Wind Project is a 200 MW wind development located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota and is being constructed on approximately 23,000 acres of leased land. The project will utilize 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year PPA, all energy, capacity and renewable energy credits from the project will be sold to Northern States Power Company, a subsidiary of Xcel Energy Inc., which is a diversified utility operating in the midwest U.S. Construction is expected to begin in the second quarter of 2015, with total costs estimated at U.S. $322.8 million. It is anticipated that the Odell Project will qualify for U.S. federal production tax credits having satisfied the Internal Revenue Service 5% beginning of construction investment safe-harbor guidance. Accordingly, approximately 60% of the permanent project financing is expected to be funded by tax equity investors.

The Generation Group's participation in the project will be via a 50% equity interest in a new joint venture with a third party developer. The Company is accounting for the joint venture as an equity method investment since both partners have joint control of the new venture. The Generation Group holds an option to acquire the other 50% interest on commencement of operations, which is expected in late 2015 or early 2016.

Val-Éo Wind Project

Phase one of the Val-Éo Wind Project is located in the local municipality of Saint-Gideon de Grandmont, 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 the Generation Group. The first 24 MW phase of the project is expected to be comprised of eight wind turbines, producing approximately 66.0GW-hr annually. Construction of the first 24 MW phase of the project is expected to begin in 2015 with commercial operations commencing in 2016. The second phase of the project would entail the development of an additional 101 MW. The permitting and the Environmental Impact Assessment are ongoing with a projected provincial minister's decree in early 2015.

The Generation Group's equity interest in the project is subject to final negotiations with the Val-Éo community cooperative but, in any event, will not be less than 25%. It is believed that the first 24 MW phase of the Val-Éo Wind Project will qualify as Canadian Renewable Conservation Expense and therefore the project will be entitled to a refundable tax credit equal to approximately $18.0 million.

Commission de Protection du Territoire Agricole Quebec ("CPTAQ") approval has been received for 8 turbine locations, roads, and the collection system. Land option agreements have all been secured, and the process of converting these options is currently underway. Proposals for the procurement of the substation and balance of plant have been received and evaluated. The final construction schedule is pending the signing of the turbine supply agreement.

Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MW project adjacent to the Generation Group's 20 MW Bakersfield I Solar Project in Kern County, California, which is currently under construction.

The 10 MW Bakersfield II Solar Project executed a 20 year PPA on September 22, 2014 with a large California based electric utility. The project will be located on 64 acres of land adjacent to the 20 MW Bakersfield I Solar Project. Construction of Bakersfield I Solar is nearing completion, with commercial operations expected to occur in the first quarter of 2015.

The total project cost for Bakersfield II Solar of approximately U.S. $27.0 million will be funded with a combination of senior debt, common equity, and contributions from tax equity investors. Consistent with financing structures utilized for U.S. based renewable energy projects including Bakersfield I Solar, it is anticipated that Bakersfield II Solar will source financing in the amount of approximately 40% of the capital costs from certain tax equity investors.

Construction of Bakersfield II Solar is anticipated to commence in mid-2015 following receipt of local permits and finalization of necessary construction contracts, subject to approval by the APUC board of directors. Commercial operation is targeted to occur in the first half of 2016.

Amherst Island Wind Project

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

The Amherst Island Wind Project is currently contemplated to use Class III wind turbine generator technology. The available wind resource is forecast to produce approximately 235 GW-hrs of electrical energy annually, depending upon the final turbine selection for the project. Final negotiations on the turbine supply agreement is ongoing. Total capital costs for the facility are currently estimated to be $260 million, and engineering, procurement and construction contractor selection is underway. The financing of the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied.

The Renewable Energy Approval ("REA") application was submitted in April 2013 and posted to the environmental registry in early January 2014 and has been undergoing technical review. Changes to the project design have been initiated to optimize construction and project performance, which will require a modification of the application documents. Once the REA is issued in final form, it may be appealed by interested parties within 15 days of its release. If the REA is appealed, the appeal process is expected to take up to 6 months. Other permitting processes are progressing according to schedule. The project has a planned construction time frame of 12 to 18 months with most of the construction expected to occur in 2016.

Chaplin Wind Project

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

The project will be split into two phases where Phase I will approximate 35 MW of the total project and is currently planned to be operational in 2017. The first phase will involve installing test turbines to prove the project viability. The second phase, the infill construction phase, will only commence provided the results of the first phase are successful.

The total facility will be constructed at an estimated capital cost of $340.0 million and consist of approximately 77 multi-megawatt wind turbines. In the total project's first full year of operation, the Generation Group expects to achieve EBITDA of $36.5 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 favorable location by interconnecting with a nearby 138Kv line and will be compliant with SaskPower's latest interconnection requirements.

In March 2014, after review of the Project Proposal Environmental Assessment and Supplemental documentation (including the preliminary proposed layout), the project was deemed a development by the Environmental Assessment Branch. An additional detailed environmental review is currently being completed. It is anticipated that the Environmental Assessment documentation will be submitted to the government in the first quarter of 2015. The expected capital costs of the project are approximately $340 million. The Generation Group anticipates entering into a partnership and development agreement using a similar structure to what was utilized in the development of the Red Lily I Facility, in order to facilitate the development of the project and to optimize returns.

Ontario RFP Qualification

The Generation Group has qualified for participation in the anticipated 2015 Large Renewable Procurement I process with the IESO. The Generation Group may submit offers into the expected RFP for up to 100 MW of solar power and up to 100 MW of wind power. The IESO is expected to award up to 140 MW of solar projects and 300 MW of wind projects. RFP bids are due on September 1, 2015, with successful bidders being announced in December 2015.

DISTRIBUTION BUSINESS GROUP

The Distribution Group operates rate-regulated utilities providing distribution services to approximately 488,000 connections in the natural gas, electric, water and wastewater sectors. The Distribution Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Distribution Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

Utility System Type	December 31, 2014		December 31, 2013	
(all dollar amounts in U.S. $ millions)	Assets	Connections	Assets	Connections
Electricity	**$ 325.0**	**93,000**	$ 276.6	92,000
Natural Gas	**726.0**	**292,000**	661.5	292,000
Water and Wastewater	**261.2**	**103,000**	233.0	97,400
Total	**$ 1,312.2**	**488,000**	$ 1,171.1	481,400
Accumulated Deferred Income Taxes	**$ 79.6**		$ 66.5	

The Distribution Group aggregates the performance of its utility operations by utility system type – electricity, natural gas, and water and wastewater systems.

The electric distribution systems are comprised of regulated electrical distribution utility systems and serve approximately 93,000 connections in the states of California and New Hampshire.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 292,000 connections located in the states of New Hampshire, Illinois, Iowa, Missouri, Georgia, and Massachusetts.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 103,000 connections located in the states of Arkansas, Arizona, Texas, Illinois, and Missouri.

	Three months ended December 31, 2014 U.S. $ (millions)		Three months ended December 31, 2013 U.S. $ (millions)		Three months ended December 31, 2014 Can $ (millions)		Three months ended December 31, 2013 Can $ (millions)
Revenue							
Utility electricity sales and distribution		**47.8**		41.9		**54.4**	46.4
Less: Cost of Sales – Electricity		**(29.9)**		(25.2)		**(34.2)**	(26.5)
Net Utility Sales - Electricity	**$**	**17.9**	$	16.7	**$**	**20.2**	$ 19.9
Utility natural gas sales and distribution		**102.5**		83.5		**116.8**	88.0
Less: Cost of Sales – Natural Gas		**(65.6)**		(54.1)		**(74.9)**	(57.1)
Net Utility Sales - Natural Gas	**$**	**36.9**	$	29.4	**$**	**41.9**	$ 30.9
Net Utility Sales - Water Distribution & Wastewater Treatment		**15.0**		14.0		**18.6**	14.6
Gas Transportation		**6.8**		4.5		**7.7**	4.7
Other Revenue		**3.0**		1.2		**3.5**	1.3
Net Utility Sales	**$**	**79.6**	$	65.8	**$**	**91.9**	$ 71.4
Operating expenses		**(39.7)**		(34.0)		**(46.2)**	(35.6)
Other income		**0.8**		0.7		**0.9**	0.6
Distribution Group operating profit	**$**	**40.7**	$	32.5	**$**	**46.6**	$ 36.4

2014 Fourth Quarter Operating Results

For the three months ended December 31, 2014, the Distribution Group reported an operating profit of U.S. $40.7 million, as compared to U.S. $32.5 million for the comparable period in the prior year. The increase is primarily due to implementation of higher rates at the Granite State Electric and Peach State Gas Systems and the acquisition of the New England Gas System on December 20, 2013. Detailed results are discussed in the following sections. Measured in Canadian dollars, the group's operating profit was $46.6 million, as compared to $36.4 million for the comparable period in the prior year. In addition to the factors described below, operating profit measured in Canadian dollars increased by $5.9 million due to a stronger U.S. dollar.

Electric Distribution Systems

	Three months ended December 31	
	2014	**2013**
Average Active Electric Connections For The Period		
Residential	**80,000**	78,000
Commercial and Industrial	**12,000**	12,000
Total Average Active Electric Connections For The Period	**92,000**	90,000
Customer Usage (GW-hrs)		
Residential	**134.9**	146.4
Commercial and Industrial	**230.5**	222.5
Total Customer Usage (GW-hrs)	**365.4**	368.9

For the three months ended December 31, 2014 the electric distribution systems' usage totalled 365.4 GW-hrs, as compared to 368.9 GW-hrs for the same period in 2013, a decrease of 3.5 GW-hrs. The decrease in residential usage can be primarily attributed to a lower number of heating degree days experienced at the CalPeco Electric System's service territory. A heating degree day is generally defined as the number of degrees that a day's average temperature is below 65 degrees Fahrenheit (18 degrees Celsius).

For the three months ended December 31, 2014, the electric distribution systems' revenue from utility electricity sales totalled U.S. $47.8 million, as compared to U.S. $41.9 million during the same period in 2013, an increase of U.S.$5.9 million, or 14.1%. For the three months ended December 31, 2014, fuel and purchased power costs for the electric distribution systems totalled U.S. $29.9 million, as compared to U.S. $25.2 million during the same period in 2013, an increase of U.S. 4.7 million, or 18.7%.

The purchase of electricity by the electric distribution systems is a significant revenue driver and component of operating expenses, however these costs are effectively passed through to its customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the three months ended December 31, 2014, net utility sales for the electric distribution systems were U.S. $17.9 million, as compared to U.S. $16.7 million during the same period in 2013, an increase of U.S. $1.2 million, or 7%. The increase in net utility sales is primarily attributed to increased rates at the Granite State Electric System as a result of finalization of the general rate case in March 2014. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues are not impacted by fluctuations in customer demand due to the variations in the weather conditions and changes in the number of customers. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement each month. The electricity commodity continues to be passed through to the CalPeco Electric System's customers according to their consumption.

Natural Gas Distribution Systems

	Three months ended December 31,	
	2014	**2013**
Average Active Natural Gas Connections For The Period		
Residential	**248,000**	217,000
Commercial and Industrial	**27,000**	24,000
Total Average Active Natural Gas Connections For The Period	**275,000**	241,000
Customer Usage (MMBTU)		
Residential	**3,918,000**	3,376,000
Commercial and Industrial	**2,885,000**	2,779,000
Total Customer Usage (MMBTU)	**6,803,000**	6,155,000

For the three months ended December 31, 2014, usage at the natural gas distribution systems totalled 6,803,000 MMBTU, as compared to 6,155,000 MMBTU during the same period in 2013, an increase of 648,000 MMBTU, or 10.5%. The increase in natural gas usage, as compared to the same period in 2013, can primarily be attributed to the acquisition of the

New England Gas System on December 20, 2013, at which usage totalled 1,053,000 MMBTU, and a higher number of heating degree days experienced in the Peach State Gas System's service territory. The increase was partially offset by a lower number of heating degree days experienced in the EnergyNorth Gas System and the Midstates Gas Systems service territories, as compared to the same period in 2013.

For the three months ended December 31, 2014, revenue excluding transportation revenue from natural gas sales and distribution totalled U.S. $102.5 million, as compared to U.S. $83.5 million during the same period in 2013, an increase of U.S. $19.0 million or 22.8%. For the three months ended December 31, 2014, natural gas purchases totalled U.S. $65.6 million, as compared with U.S. $54.1 million for the same period in 2013, an increase of U.S. $11.5 million or 21.3%. The cost of natural gas is passed through to the natural gas systems' customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the three months ended December 31, 2014, net utility sales for the natural gas distribution systems, excluding transportation, totalled U.S. $36.9 million, as compared to U.S. $29.4 million during the same period in 2013, an increase of U.S. $7.5 million, or 25.5%. The increase in net utility sales can be primarily attributed to the acquisition of the New England Gas System on December 20, 2013, which contributed U.S. $4.3 million of the total increase, and a U.S. $3.1 million increase at the Peach State Gas System primarily due to increased rates as a result of the GRAM filing.

For the three months ended December 31, 2014, revenue from gas transportation sales totalled U.S. $6.8 million, as compared to U.S. $4.5 million during the same period in 2013, an increase of U.S. $2.3 million. The increase in gas transportation sales can be primarily attributed to the acquisition of the New England Gas System on December 20, 2013, which contributed U.S. $1.2 million of the total increase, and a U.S. $1.0 million increase at the EnergyNorth Gas System, primarily due to increased customer demand.

Water and Wastewater Distribution Systems	**Three months ended December 31,**	
	2014	**2013**
Average Active Connections For The Period		
Wastewater connections	**40,000**	36,900
Water distribution connections	**58,000**	55,900
Total Average Active Connections For The Period	**98,000**	92,800
Gallons Provided		
Wastewater treated (millions of gallons)	**535**	507
Water sold (millions of gallons)	**1,940**	2,080
Total Gallons Provided	**2,475**	2,587

During the three months ended December 31, 2014, the water and wastewater distribution systems provided approximately 1,940 million gallons of water to its customers and treated approximately 535 million gallons of wastewater, as compared to 2,080 million gallons of water and 507 million gallons of wastewater during the same period in 2013. The decrease in the gallons of water provided to customers can be attributed to increased precipitation, primarily in the state of Arizona during the three months ended December 31, 2014, as compared to the comparable period in the prior year.

The increase in average active wastewater and water distribution connections can be primarily attributed to the acquisition of the White Hall Water System on May 30, 2014.

For the three months ended December 31, 2014, revenue from wastewater treatment and water distribution totalled U.S. $6.9 million and U.S. $8.1 million, respectively, as compared to U.S. $6.1 million and U.S. $7.9 million, respectively, during the same period in 2013. The increase in wastewater treatment and water distribution revenue was primarily due to an increase in rates at the LPSCo Water and Sewer System, effective May 1, 2014, and the acquisition of the White Hall Water System on May 30, 2014.

Other Revenue

For the three months ended December 31, 2014, other revenue totalled U.S. $3.0 million, as compared to $1.2 million during the same period in 2014. The other revenue consists of water heater rental service and a contract to supply gas to Fort Benning.

Operating Expenses

For the three months ended December 31, 2014, operating expenses, excluding electricity purchases, totalled U.S. $39.7 million, as compared to U.S. $34.0 million during the same period in 2013, an increase of U.S. $5.7 million, or 17%. The major factors resulting in the increase in the Distribution Group's operating expenses in the three months ended December 31, 2014, as compared to the corresponding period in 2013, are set out as follows:

(all dollar amounts in U.S. $ millions)	Quarter ended December 31, 2014	
Comparative Prior Period Operating Expenses	$	34.0
Significant Changes:		
Acquisition of New England Gas System		6.3
Decrease in operating expenses at Granite State Electric Utility and EnergyNorth Gas Utility		(1.4)
Acquisition of White Hall Water System		0.2
Increase in operating expenses at CalPeco Electric System		0.2
Other		0.4
Current Period Operating Expenses	$	39.7

	Twelve months ended December 31,				Twelve months ended December 31,			
		2014 U.S. $ (millions)		2013 U.S. $ (millions)		**2014 Can $ (millions)**		2013 Can $ (millions)
Revenue								
Utility electricity sales and distribution		**186.8**		161.3		**206.7**		166.2
Less: Cost of Sales – Electricity		**(108.8)**		(94.5)		**(120.5)**		(97.4)
Net Utility Sales - Electricity	**$**	**78.0**	$	66.8	**$**	**86.2**	$	68.8
Utility natural gas sales and distribution		**378.2**		236.0		**419.9**		243.1
Less: Cost of Sales – Natural Gas		**(234.8)**		(144.5)		**(261.1)**		(148.8)
Net Utility Sales - Natural Gas	**$**	**143.4**	$	91.5	**$**	**158.8**	$	94.3
Net Utility Sales - Water Distribution & Wastewater Treatment		**58.7**		55.6		**66.4**		57.4
Gas Transportation		**23.5**		16.8		**26.1**		17.3
Other Revenue		**5.1**		1.2		**5.7**		1.3
Net Utility Sales	**$**	**308.7**	$	231.9	**$**	**343.2**	$	239.1
Operating expenses		**(162.7)**		(127.5)		**(180.4)**		(131.6)
Other income		**3.0**		3.1		**3.4**		3.2
Distribution Group operating profit	**$**	**149.0**	**$**	**107.5**	**$**	**166.2**	$	110.7

2014 Twelve Month Operating Results

For the twelve months ended December 31, 2014, the Distribution Group reported an operating profit of U.S. $149.0 million, as compared to U.S. $107.5 million for the comparable period in the prior year. The increase is primarily due to the acquisition of the New England Gas System on December 20, 2013, the acquisition of the Peach State Gas System on April 1, 2013, and higher rates at the Granite State Electric System. Detailed results are discussed in the following sections. Measured in Canadian dollars, the group's operating profit was $166.2 million, as compared to $110.7 million for the comparable period in the prior year. In addition to the factors discussed below, operating profit measured in Canadian dollars increased by $17.2 million due to a stronger U.S. dollar.

Electric Distribution Systems

	Twelve months ended December 31,	
	2014	**2013**
Average Active Electric Connections For The Period		
Residential	**79,000**	78,000
Commercial and Industrial	**12,000**	12,000
Total Average Active Electric Connections For The Period	**91,000**	90,000
Customer Usage (GW-hrs)		
Residential	**557.4**	585.9
Commercial and Industrial	**933.4**	905.5
Total Customer Usage (GW-hrs)	**1,490.8**	1,491.4

For the twelve months ended December 31, 2014, the electric distribution systems' usage totalled 1,490.8 GW-hrs, as compared to 1,491.4 GW-hrs for the same period in 2013. The decrease in residential usage can be primarily attributed to a lower number of heating degree days experienced at the CalPeco Electric System's service territory.

For the twelve months ended December 31, 2014, the electric distribution systems revenue from utility electricity sales totalled U.S. $186.8 million, as compared to U.S. $161.3 million during the same period in 2013, an increase of U.S. $25.5 million, or 15.8%. For the twelve months ended December 31, 2014, fuel and purchased power costs for the electric distribution systems totalled U.S $108.8 million, as compared to U.S. $94.5 million for the same period in 2013, an increase of U.S. $14.3 million, or 15.1%.

The purchase of electricity by the electric distribution systems is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the twelve months ended December 31, 2014, net utility sales for the electric distribution systems were U.S. $78.0 million, as compared to U.S. $66.8 million for the same period in 2013, an increase of U.S. $11.2 million, or 16.8%. The increase in net utility sales can be primarily attributed to an increase in distribution rates to customers from finalization of the Granite State Electric System's general rate case, as well as U.S. $2.5 million in additional revenue recognized in the first quarter of 2014, which represented the difference from the interim rates previously granted to the Granite State Electric System and the final rates retroactive to July 1, 2013. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues are not impacted by fluctuations in customer demand due to the variations in the weather conditions and changes in the number of customers. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement each month. The electricity commodity continues to be passed through to the CalPeco Electric System's customers according to their consumption.

Natural Gas Distribution Systems

	Twelve months ended December 31,	
	2014	**2013**
Average Active Natural Gas Connections For The Period		
Residential	**248,000**	204,000
Commercial and Industrial	**26,000**	23,000
Total Average Active Natural Gas Connections For The Period	**274,000**	227,000
Customer Usage (MMBTU)		
Residential	**18,915,000**	12,401,000
Commercial and Industrial	**12,673,000**	8,706,000
Total Customer Usage (MMBTU)	**31,588,000**	21,107,000

For the twelve months ended December 31, 2014, customer usage at the natural gas distribution systems totalled 31,588,000 MMBTU, as compared to 21,107,000 MMBTU during the same period in 2013, an increase of 10,481,000 MMBTU, or 49.7%. The increase in natural gas usage, as compared to the same period in 2013, can be primarily attributed to the acquisitions of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013; the New England Gas System usage totalled 5,273,000 MMBTU.

For the twelve months ended December 31, 2014, revenue from natural gas sales and distribution totalled U.S. $378.2 million, as compared to U.S. $236.0 million during the same period in 2013, an increase of U.S. $142.2 million. For the twelve months ended December 31, 2014, natural gas purchases totalled U.S. $234.8 million, as compared to U.S. $144.5 million for the same period in 2013, an increase of U.S. $90.3 million. The cost of natural gas is passed through to the natural gas distribution systems' customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of results. For the twelve months ended December 31, 2014, net utility sales, excluding transportation, for the natural gas distribution systems totalled U.S. $143.4 million, as compared to U.S. $91.5 million during the same period in 2013, an increase of U.S. $51.9 million, or 57%. The increase is attributed as follows: U.S. $30.5 million increase from the New England Gas System, which was acquired on December 20, 2013; U.S. $4.5 million increase from the EnergyNorth Gas System, primarily due to the colder winter weather experienced during the first quarter of 2014, as compared to the first quarter of 2013; U.S. $15.1 million increase from the Peach State Gas System; primarily attributed to the inclusion of twelve months of operating results in 2014, as compared to nine months in 2013; increased rates as a result of the GRAM filing at the Peach State Gas System; and a U.S. $1.8 million increase from the Midstates Gas Systems due to the colder winter weather experienced during the first quarter of 2014, as compared to the first quarter of 2013.

For the twelve months ended December 31, 2014, revenue from gas transportation sales totalled U.S. $23.5 million, as compared to U.S. $16.8 million during the same period in 2013, an increase of U.S. $6.7 million. The increase in gas transportation sales can be primarily attributed to the acquisition of the New England Gas System on December 20, 2013, which contributed U.S. $6.1 million of the total increase.

Water and Wastewater Distribution Systems

	Twelve months ended December 31,	
	2014	**2013**
Average Active Connections For The Period		
Wastewater connections	**39,000**	36,600
Water distribution connections	**58,000**	55,800
Total Average Active Connections For The Period	**97,000**	92,400
Gallons Provided		
Wastewater treated (millions of gallons)	**2,127**	2,034
Water sold (millions of gallons)	**8,310**	8,162
Total Gallons Provided	**10,437**	10,196

Average active wastewater and water distribution connections increased primarily due to the acquisition of the White Hall Water and Sewer System on May 30, 2014.

During the twelve months ended December 31, 2014, the water and wastewater distribution systems provided approximately 8,310 million gallons of water to its customers and treated approximately 2,127 million gallons of wastewater, as compared to 8,162 million gallons of water and 2,034 million gallons of wastewater during the same period in 2013. The increase in water sold can be primarily attributed to the acquisition of the White Hall Water System on May 30, 2014, and an additional month of operations from the Pine Bluff Water System in the first twelve months of 2014, as compared to the first twelve months of 2013. The increase in wastewater treated is primarily attributed to an increase in wastewater treated at our sewer utilities located in the state of Arizona.

For the twelve months ended December 31, 2014, revenue from wastewater treatment and water distribution totalled U.S. $26.1 million and U.S. $32.6 million, respectively, as compared to U.S. $24.3 million and U.S. $31.3 million, respectively, during the same period in 2013. Increased rates at the LPSCo Water and Sewer System, effective May 1, 2013, Rio Rico Water System, effective August 1, 2013, and Woodmark Waste System, effective October 1, 2013, are the primary drivers of the increase along with the acquisition of the White Hall Water System on May 30, 2014.

Other Revenue

For the twelve months ended December 31, 2014, other revenue totalled U.S. $5.1 million, as compared to U.S. $1.2 million during the same period in 2014. The other revenue consists of water heater rental service and a contract to supply gas to Fort Benning.

Operating Expenses

For the twelve months ended December 31, 2014, operating expenses, excluding electricity purchases, totalled U.S. $162.7 million, as compared to U.S. $127.5 million during the same period in 2013, an increase of U.S. $35.2 million, or 28%. The major factors resulting in the increase in DBG operating expenses in the twelve months ended December 31, 2014, as compared to the corresponding period in 2013, are set out as follows:

(all dollar amounts in U.S. $ millions)	**Year to date December 31, 2014**
Comparative Prior Period Operating Expenses	$ 127.5
Significant Changes:	
Acquisition of New England Gas System	26.3
Increase in operating expenses at the Granite State Electric System and EnergyNorth Gas System	4.6
Increase in operating expenses at the Peach State Gas System	2.2
Increase in operating expenses at the Midstates Gas Systems	0.8
Acquisition of White Hall Water System	0.5
Other	0.8
Current Period Operating Expenses	$ 162.7

The primary reason for the increase in operating expenses for the twelve months ended December 31, 2014, as compared to the corresponding period in 2013, was the acquisition of the New England Gas System on December 20, 2013. The full year of operating expenses, as compared to eleven days of operating expenses in 2013, contributed an additional U.S. $26.3 million.

Operating expenses at the Granite State Electric and EnergyNorth Gas Systems were U.S. $4.6 million higher than the prior fiscal year, primarily due to increased bad debt expense in the first nine months of the year, a property tax assessment related to a prior assessment year, and additional work for leak repairs.

The increase in operating expenses at the Peach State Gas System of U.S. $2.2 million was primarily due to twelve months of operation during the twelve months ended December 31, 2014, as compared to nine months of operation during the nine months ended December 31, 2013. The Peach State Gas System was acquired on April 1, 2013.

The increase in operating expenses at the Midstates Gas Systems of U.S. $0.8 million can be primarily attributed due to increased costs for billings services and communication expenses.

The acquisition of the White Hall Water System on May 30, 2014 resulted in an increase in operating expenses of U.S. $0.5 million during the twelve months ended December 31, 2014.

Regulatory Proceedings

The following table summarizes the major regulatory proceedings within the Distribution Group currently underway:

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Completed Rate Cases				
Granite State Electric System	New Hampshire	General Rate Case	$13,000	Final Order issued on March 2014 approving a $9.8 million rate increase effective April 1, 2014.
Granite State Electric System	New Hampshire	General Rate Case - Step Adjustment	$1,200	Final Order issued on March 2014 approving a $1.1 million in step increase for 2014 effective April 1, 2014
Peach State Gas System	Georgia	GRAM	$4,900	Final Order issued on May 2014 approving a $3.2 million rate increase retroactive to February 1, 2014, and the recovery of $1.7 million of carrying charges on deferred rate base in a future GRAM filing.
Peach State Gas System	Georgia	GRAM	$3,900	Final Order issued on December 2014 approving a $3.7 million rate increase effective February 1, 2015.
LPSCo Water System	Arizona	General Rate Case	$3,000	Final Order issued on April 2014 approving a $1.8 million rate increase effective May 1, 2014.
Missouri Gas System	Missouri	General Rate Case	$7,600	Final Order issued on December 2014 approving a $4.9 million rate increase effective January 2, 2015.
Illinois Gas System	Illinois	General Rate Case	$5,700	Final Order issued on February 11, 2015 approving a $4.6 million revenue increase effective February 20, 2015.
Pending Rate Cases				
Pine Bluff Water System	Arkansas	General Rate Case	$2,500	Application was filed on July 2, 2014; Order expected in Q2 2015
EnergyNorth System	New Hampshire	General Rate Case	$16,100	Application filed on August 1, 2014; a temporary rate increase was approved on November 21, 2014 allowing a $7.4M interim increase effective December 1, 2014, retroactive to November 1, 2014 upon approval of permanent rates. A final permanent rates decision is expected in Q3 2015.

Completed Rate Cases

In the first quarter of 2013, the Granite State Electric System filed a rate case with the New Hampshire Public Utilities Commission ("NHPUC") seeking an increase in rates of U.S. $13.0 million, and an additional U.S. $1.2 million increase in 2014 subject to the completion of certain capital projects. On March 17, 2014, the commission approved a settlement of U.S. $9.8 million and U.S. $1.1 million step increase for 2014.

On October 1, 2013, the Peach State Gas System filed an application for an increase in revenue of U.S. $4.9 million in its annual GRAM filing with the GPSC. In January 2014, the Distribution Group and the Staff of the GPSC agreed to a settlement which will provide an annual revenue increase of U.S. $3.2 million, and the recovery of U.S. $1.7 million of carrying charges on deferred rate base in a future GRAM filing. Commission approval was received in May 2014, with new rates effective as of June 1, 2014.

On October 1, 2014, the Peach State Gas System filed an application for an increase in revenue of U.S. $3.9 million in its annual GRAM filing with the GPSC. New rates to be effective February 1, 2015 for the period February 1, 2015, through January 31, 2016 were to reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 30, 2014 (Historic Test Year) with adjustments for the 12 months ending August 31, 2015 (Forward Looking Test Year). Commission approval was received on December 2, 2014.

On February 28, 2013, LPSCo Water System filed a general rate case with the Arizona Corporation Commission related to the LPSCo Water System sought, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application sought recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application sought 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. In April 2014 the commission approved a $1.8 million increase in rates effective on May 1, 2014.

On February 6, 2014, the Midstates Gas System filed a rate case with the Missouri Public Service Commission ("MOPSC") seeking an increase in revenue of U.S. $7.6 million, consisting of U.S. $6.3 million in new, incremental revenue and U.S. $1.3 million through the ISRS surcharge (infrastructure system replacement surcharge). The filing is based on a test year ending September 30, 2013, with revenues, expenses and rate bases adjusted to reflect known and measurable changes through April 30, 2014. The case has concluded and an Order was issued on December 3, 2014, approving a U.S. $4.9 million revenue increase effective January 2, 2015.

On March 31, 2014, the Midstates Gas System filed a rate case with the Illinois Commerce Commission ("ICC") seeking an increase in EBITDA of U.S. $5.7 million. The filing is based on a test year that includes anticipated capital expenditures within 2014 and 2015. The case has concluded and an Order was issued on February 11, 2015, approving a U.S. $4.6 million revenue increase effective February 20, 2015.

Pending Rate Cases

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

On August 1, 2014, the EnergyNorth Natural Gas System in New Hampshire filed an application for an increase in revenue of U.S. $16.1 million, or approximately 9.6%. The application includes a revenue decoupling proposal and seeks recovery of capital costs related to the conversion of the system to the Distribution Group ownership. Expected implementation of the new permanent rates is in the third quarter of 2015. A temporary rate increase was approved on November 21, 2014 allowing a U.S. $7.4 million interim rate increase effective December 1, 2014, retroactive to November 2014 upon approval of permanent rates.

Acquisition Approval Applications

On September 19, 2014, the Distribution Group announced the entering into an agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure, to acquire the regulated water distribution utility Park Water Company (“Park Water System”). Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. The three utilities collectively serve approximately 74,000 customer connections and have more than 1,000 miles of distribution mains.

The acquisition requires the approval of both the California Public Utilities Commission ("CPUC") and the Montana Public Service Commission ("MPSC"). An approval application was filed on November 24, 2014 with the CPUC seeking approval for APUC, through its wholly owned subsidiary Liberty Utilities Co., to acquire the two water utilities located in California owned by the Park Water Company, Park Central Basin and Apple Valley Ranchos Water. A decision on the California application is expected in the third quarter of 2015. An approval application was also filed on December 15, 2014 with the MPSC seeking approval for APUC, through its wholly owned subsidiary Liberty Utilities Co., to effectively acquire Mountain Water Company. A decision on the application is expected in the fourth quarter of 2015.

Mountain Water Company is the water utility in Western Montana owned by Park Water Company which serves the municipality of Missoula. Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula (See “Regulatory Risk”).

TRANSMISSION BUSINESS GROUP

In 2014, APUC created the Transmission Group which the Company believes complements the growth of the Generation and Distribution Groups. The Transmission Group is responsible for identifying, evaluating, and capitalizing upon natural gas pipeline and electric transmission asset opportunities in North America.

For its first major project on November 24, 2014, the Transmission Group announced an agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan, Inc. Specifically, Kinder Morgan Operating L.P. “A,” a wholly owned subsidiary of Kinder Morgan, Inc., and Liberty Utilities (Pipeline & Transmission) Corp., a wholly owned subsidiary of APUC, have agreed to form a new entity ("Northeast Expansion LLC") to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas transmission pipeline to be located between Wright, NY and Dracut, MA (the “Project”), which will be operated by Tennessee Gas Pipeline Company, L.L.C. (“Tennessee”). The Project is scalable up to 2.2 billion cubic feet per day (Bcf/d), and the pipeline capacity will be contracted with local distribution utilities, and other customers, to help ease constraints on natural gas supply in the northeast U.S. and help ensure much needed reliability to the power-generation grid. It is anticipated that Tennessee will receive a FERC certificate in the fourth quarter of 2016, with construction anticipated to begin in January 2017 and commercial operations expected by Nov. 1, 2018.

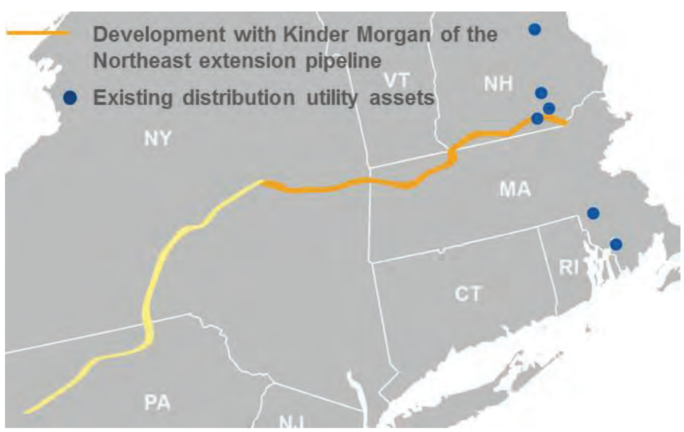
Under the agreement, APUC will initially subscribe for a 2.5% interest in Northeast Expansion LLC. APUC also has an opportunity to increase its participation up to 10%. The total capital investment opportunity for APUC could be up to U.S. $400 million, depending on the final pipeline configuration and design capacity.

The U.S. $3-$4 billion infrastructure project consists of 188 miles of pipeline and six new compressor stations to be constructed through the states of New York, Massachusetts and New Hampshire. The pipeline is designed to provide up to 2.2 Bcf/day of firm gas deliveries to gas distribution utilities, gas fired generation, industrial customers and other New England consumers. Given the proposed route of the project, the Distribution Group will also look to economically expand its gas distribution utility footprint in New Hampshire as well to serve over twenty new communities with natural gas service.

Under the current September 15, 2014 application before the FERC under Docket No. PF 14 - 22, the project sponsor has proposed the following development calendar of events for proceeding with the project:

1st Draft of the Environmental Review	March 6, 2015
2nd Draft of the Environmental Review	June 5, 2015
FERC Section 7 Certificate Application Filed	September, 2015
FERC Section 7 Certificate Approval Received	October 31, 2016
Targeted In- Service of Core NED Project	November 1, 2018

The project route has recently been modified to address a number of comments raised by various stakeholders and is shown as the orange solid line on the map below and has been filed with the FERC for further consideration.



Continued development of the project in 2015 will include ongoing environmental research, further outreach programs, development of procurement plans for long lead time items and continued marketing of available firm capacity prior to and following the September 2015 FERC application.

APUC: CORPORATE AND OTHER EXPENSES

APUC: CORPORATE AND OTHER EXPENSES	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
Corporate and other expenses:				
Administrative expenses	**$ 10.5**	$ 5.2	**$ 34.7**	$ 23.5
(Gain)/Loss on foreign exchange	**0.3**	(0.1)	**(1.1)**	(0.6)
Interest expense	**14.1**	14.4	**62.4**	53.4
Interest, dividend and other Income[1]	**0.5**	0.7	**3.2**	2.5
Write down of long lived assets	**0.3**	—	**8.5**	—
Acquisition-related costs	**1.6**	0.6	**2.6**	2.1
(Gain)/Loss on derivative financial instruments	**2.0**	(2.7)	**1.4**	(5.2)
Income tax expense	**3.7**	5.2	**16.8**	9.2

[1] Excludes income directly pertaining to the Generation and Distribution Groups (disclosed in the relevant sections).

2014 Annual Corporate and Other Expenses

During the year ended December 31, 2014, administrative expenses totalled $34.7 million, as compared to $23.5 million in the same period in 2013. The expense increase for the period is primarily due to approximately $6.3 million of expenses previously classified as direct operating expenses that have been reclassified in 2014 as administrative expenses as certain functions are now being performed centrally as part of a shared services function across the entire company. The remaining $4.9 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the company's growth.

For the year ended December 31, 2014, interest expense totalled $62.4 million, as compared to $53.4 million in the same period in 2013. The increased interest expense is a result of new indebtedness incurred during the first half of 2014 used to partially finance new acquisitions and fund other growth initiatives.

For the year ended December 31, 2014, interest, dividend and other income totalled $3.2 million, as compared to $2.5 million in the same period in 2013, an increase of $0.7 million due to an incremental $2.5 million in rental income earned in 2014, partially offset by $1.8 million in decreased dividends from APUC's share investment in the Kirkland and Cochrane Thermal Facilities.

For the year ended December 31, 2014, acquisition related costs totalled $2.6 million, as compared to $2.1 million in the same period in 2013. Acquisition related costs will vary from period to period depending on the level of activity and complexity associated with various acquisitions.

For the year ended December 31, 2014, loss on derivative financial instruments totalled $1.4 million, as compared to a gain of $5.2 million in the same period in 2013. The decrease was primarily driven by derivative losses on hedges to purchase electricity for resale at contracted rates that differ from the market rate.

An income tax expense of $16.8 million was recorded in the year ended December 31, 2014, as compared to an income tax expense of $9.2 million during the same period in 2013. The increase in income tax expense for the year ended December 31, 2014 is primarily due to increased earnings from operations, increased deferred taxes on HLBV income, a stronger U.S. dollar, and other items permanently non-deductible for tax purposes.

2014 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2014, administrative expenses totalled $10.5 million, as compared to $5.2 million in the same period in 2013. The increase was primarily due to $3.9 million in additional costs incurred to administer APUC's operations as a result of the company's growth and $1.4 million of expenses previously classified as direct operating expenses that have been reclassified in 2014 as administrative expenses as certain functions are now being performed centrally as part of a shared services function across the entire company.

For the quarter ended December 31, 2014, interest expense totalled $14.1 million, as compared to $14.4 million in the same period in 2013. The decreased interest expense is a result of increased capitalization of interest expense due to the ongoing development projects during the end of period.

For the quarter ended December 31, 2014, interest, dividend and other income totalled $0.5 million, as compared to $0.7 million in the same period in 2013. Interest, dividend and other income primarily consists of $0.7 million in rental income, partially offset by $0.3 million in decreased dividends from APUC's share investment in the Kirkland and Cochrane Thermal Facilities.

For the quarter ended December 31, 2014, loss on derivative financial instruments totalled $2.0 million, as compared to a gain of $2.7 million in the same period in 2013. The decrease was primarily driven by derivative losses on hedges to purchase electricity for resale at contracted rates that differ from the market rate.

An income tax expense of $3.7 million was recorded in the three months ended December 31, 2014, as compared to an income tax expense of $5.2 million during the same period in 2013. The decrease in income tax expense for the quarter ended December 31, 2014 is primarily due to a reversal of an alternative minimum tax liability accrued in prior year, which is no longer a liability based on the amended legislation in the Internal Revenue Code, offset by increased earnings from operations, increased deferred taxes on HLBV income, and a stronger U.S. dollar.

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

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

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
Net earnings attributable to Shareholders	$ 31.6	$ 13.2	$ 75.7	$ 20.3
Add (deduct):				
Net earnings / (loss) attributable to the non-controlling interest, exclusive of HLBV	**0.5**	3.4	**5.0**	9.6
Loss from discontinued operations	**1.5**	6.7	**2.1**	42.0
Income tax expense	**3.7**	5.2	**16.8**	9.2
Interest expense	**14.1**	14.4	**62.4**	53.4
Loss / (Gain) on sale of assets	**(0.1)**	0.6	**(0.4)**	0.8
Non-cash write downs	**0.3**	—	**8.5**	—
Acquisition costs	**1.6**	0.6	**2.6**	2.1
(Gain) / Loss on derivative financial instruments	**2.0**	(2.7)	**1.4**	(5.2)
Realized gain / (loss) on energy derivative contracts	**(0.2)**	0.3	**3.6**	0.5
(Gain) / Loss on foreign exchange	**0.3**	(0.1)	**(1.1)**	(0.6)
Depreciation and amortization	**29.0**	26.9	**114.0**	96.0
Adjusted EBITDA	**$ 84.3**	$ 68.5	**$ 290.6**	$ 228.1

Hypothetical Liquidation at Book Value ("HLBV") represents the value of net tax attributes earned by the Generation Group in the period from electricity generated by certain of its U.S. wind power generation facilities. The value of net tax attributes earned in the three and twelve months ended December 31, 2014 amounted to approximately $8.9 million and $27.2 million, respectively.

For the year ended December 31, 2014, Adjusted EBITDA totalled $290.6 million, as compared to $228.1 million during the same period in 2013, an increase of $62.5 million. For the quarter ended December 31, 2014, Adjusted EBITDA totalled $84.3 million, as compared to $68.5 million, an increase of $15.8 million compared to the same period in 2013.

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

(all dollar amounts in $ millions)	Quarter ended December 31, 2014	Year ended December 31, 2014
Comparative Prior Period Adjusted EBITDA	$ 68.5	$ 228.1
Significant Changes:		
Generation Business Group:		
Renewable		
Increase / (decreased) hydrology resource	2.2	(2.0)
Decreased/increased wind resources for the quarter/year to date, at the U.S. Wind Facilities offset by unfavorable periodic hedge settlements shortfalls at the Minonk, Sandy Ridge and Senate facilities	3.2	2.8
Higher realized prices on sale of Renewable Energy Credits at the U.S. Wind Facilities	1.1	4.9
Start of commercial operations for the Cornwall Solar Facility	0.3	4.8
Increased wind resources at the St Leon wind facilities	0.3	3.1
Unfavorable retail pricing at AES partially offset by gains from hedge settlements and increased customer load.	1.2	(1.8)
Thermal		
Increased market prices at the Sanger and Windsor Locks Thermal Facility	0.3	1.3
Higher realized prices on sale of Renewable Energy Credits	(0.1)	0.7
Distribution Business Group:		
Increased delivery and treatment of water and wastewater systems	0.7	3.2
Increased rates at the Granite State Electric System	1.4	10.2
Changes in customer demand and higher operating expenses at the EnergyNorth and the Midstates Gas Systems	1.8	1.9
2013 Acquisition of the New England and Peach State Gas Systems	2.5	23.6
Increase earnings due to acquisition of New England Gas System's water heater rental service and the Peach State Gas System's Fort Benning operation	1.8	3.8
Administrative expense	(5.4)	(11.2)
Increased results from the stronger U.S. dollar	6.6	18.4
Other	(2.1)	(1.2)
Current Period Adjusted EBITDA	$ 84.3	$ 290.6

Reconciliation of adjusted net earnings to net earnings

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

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

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
Net earnings attributable to Shareholders	**$ 31.6**	$ 13.2	**$ 75.7**	$ 20.3
Add (deduct):				
(Gain) / Loss from discontinued operations, net of tax	**1.5**	6.7	**2.1**	42.0
(Gain) / Loss on derivative financial instruments, net of tax	**1.2**	(1.6)	**0.8**	(3.1)
Realized gain / (loss) on derivative financial instruments, net of tax	**(0.5)**	(0.2)	**0.7**	(1.2)
Write down long lived assets	**0.3**	—	**8.5**	—
(Gain) / Loss on asset disposal, net of tax	**(0.1)**	0.4	**(0.3)**	0.5
(Gain) / Loss on foreign exchange, net of tax	**0.2**	(0.1)	**(0.7)**	(0.3)
Acquisition costs, net of tax	**1.0**	0.4	**1.6**	1.3
Adjusted net earnings	**$ 35.2**	$ 18.8	**$ 88.4**	$ 59.5
Adjusted net earnings per share	**$ 0.14**	$ 0.08	**$ 0.37**	$ 0.26

For the year ended December 31, 2014, adjusted net earnings totalled $88.4 million, as compared to adjusted net earnings of $59.5 million, an increase of $28.9 million as compared to the same period in 2013. The increase in adjusted net earnings for the year ended December 31, 2014 is primarily due to higher income from operations partially offset by higher interest expense, and depreciation and amortization expense as compared to the same period in 2013.

For the three months ended December 31, 2014, adjusted net earnings totalled $35.2 million, as compared to adjusted net earnings of $18.8 million, an increase of $16.4 million as compared to the same period in 2013. The increase in adjusted net earnings for the three months ended December 31, 2014 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense, and higher interest expense as compared to the same period in 2013.

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

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

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

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
Cash flows from operating activities	**$ 96.5**	$ 28.4	**$ 192.7**	$ 98.9
Add (deduct):				
Changes in non-cash operating items	**(33.1)**	13.5	**0.5**	47.8
Cash (provided)/used in discontinued operation	**0.9**	3.5	**1.7**	4.4
Production Tax Credits received from non-controlling interests	**—**	—	**9.0**	1.7
Acquisition costs	**1.6**	0.6	**2.6**	2.1
Adjusted funds from operations	**$ 65.9**	$ 46.0	**$ 206.5**	$ 154.9
Adjusted funds from operations per share	**0.27**	0.22	**0.92**	0.73

For the year ended December 31, 2014, adjusted funds from operations totalled $206.5 million, as compared to adjusted funds from operations of $154.9 million, an increase of $51.6 million as compared to the same period in 2013.

For the three months ended December 31, 2014, adjusted funds from operations totalled $65.9 million, as compared to adjusted funds from operations of $46.0 million, an increase of $19.9 million as compared to the same period in 2013.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
GENERATION GROUP				
Renewable	**$ 59.6**	$ 18.0	**$ 197.1**	$ 46.9
Thermal	**0.5**	1.3	**4.0**	2.6
Total Generation Business Group	**$ 60.1**	$ 19.3	**$ 201.1**	$ 49.5
DISTRIBUTION GROUP	**$ 77.4**	$ 43.4	**$ 176.8**	$ 108.9
Corporate	**4.3**	—	**54.5**	—
Total	**$ 141.8**	$ 62.7	**$ 432.4**	$ 158.4

The company's consolidated capital expenditure plan for 2015 is approximately $261.0 million. The Generation Group expects to invest approximately $107.0 million primarily in connection with the development of its existing project pipeline. The Distribution Group expects to invest approximately $147.0 million primarily to improve the reliability and efficiency of its gas and electric utility distribution systems. The Transmission Group expects to invest approximately $7.0 million for the natural gas pipeline transmission project.

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

2014 Twelve Month Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2014, the Generation Group incurred capital expenditures of $201.1 million, as compared to $49.5 million during the comparable period in 2013.

During the twelve months ended December 31, 2014, the Generation Group's Renewable Energy Division spent $197.1 million in capital expenditures, as compared to $46.9 million in the comparable period in 2013. The capital expenditures primarily relate to the completion of the Cornwall Solar and St. Damase Wind Facilities, and the construction of the Bakersfield Solar and Morse Wind Projects. The Generation Group's Thermal Energy Division net capital expenditures were $4.0 million, as compared to $2.6 million in the comparable period in 2013. The capital expenditures in the year were $1.2 million at Windsor Locks and $2.8 million at Sanger.

During the twelve months ended December 31, 2014, the Distribution Group invested $176.8 million in capital expenditures, as compared to $108.9 million during the comparable period in 2013. The capital expenditures primarily relate to the completion of a second supply line, reliability enhancements, and new business projects at the Granite State Electric System; improvement and replenishment opportunities at the CalPeco Electric System; leak prone pipe replacements, leak repairs and pipeline corrosion protection systems relating to enhancing safety and reliability at the EnergyNorth, Midstates, New England, and Peach State Gas Systems; and improvement, replenishment and new business projects at the water and wastewater utilities located in Arizona and at the Pine Bluff Water System.

2014 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2014, the Generation Group incurred capital expenditures of $60.1 million, as compared to $19.3 million during the comparable period in 2013. During the three months ended December 31, 2014, the Generation Group's Renewable Energy Division spent $59.6 million in capital expenditures, as compared to $18.0 million in the comparable period in 2013. The capital expenditures primarily relate to completion of construction at the St. Damase Wind Facility and the continued construction at the Bakersfield Solar Project. The Generation Group's Thermal Energy Division net capital expenditures were $0.5 million, as compared to $1.3 million in the comparable period in 2013. The 2014 thermal capital expenditures consist of $0.4 million relating to Windsor Locks Thermal Facility and $0.1 million relating to Sanger Thermal Facility.

During the three months ended December 31, 2014, the Distribution Group invested $77.4 million in capital expenditures, as compared to $43.4 million during the comparable period in 2013. The Distribution Group's investment was primarily related to reliability enhancements, and new business projects at the Granite State Electric System; improvement and replenishment opportunities at the CalPeco Electric System; leak prone pipe replacements, leak repairs and pipeline corrosion protection systems relating to enhancing safety and reliability at the EnergyNorth, Midstates, New England, and Peach State Gas Systems; and improvement, replenishment and new business projects at the water and wastewater utilities located in Arizona and at the Pine Bluff Water System.

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C-93), the Generation Group has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. Out of these, nine assessments have been submitted to and accepted by the Quebec government. The assessments have identified possible remedial work at seven facilities. Of these seven, remediation work has now been completed at three facilities, monitoring activities and options analysis are being performed for two facilities, and remedial work is being planned at two facilities.

The Generation Group currently estimates further capital expenditures of approximately $7.9 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:

(all dollar amounts in $ millions)	Total	2015	2016	2017	2018
Future Estimated Bill C-93 Capital Expenditures	$ 7.9	1.0	3.1	3.5	0.3

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

The Generation Group is presently working with the provincial authorities to reclassify, decommission or remove several small dams upstream of the Belleterre Hydro Facility that are not required for power generation. The Generation Group anticipates completion of any required work on these dams by 2017.

Engineering for the Riviere-du-Loup Hydro Facility was completed in 2012. Following additional geotechnical investigation in 2014, the remediation work is now estimated at $1.1 million. Completion of the remedial work is anticipated in 2015.

The dam safety study and a detailed condition assessment for the St. Alban Hydro Facility have been completed. The Generation Group anticipates engineering and regulatory review for the remediation of the main dam to be completed in 2015, with remedial work in 2016 to 2017.

On May 18, 2014, the Donnacona Hydro Facility experienced ice damage during the spring thaw and has been shut down. The Generation Group had previously planned capital expenditures for the Donnacona Hydro Facility in 2015 and 2016 in the amount of $7.8 million. It has been determined, in consultation with its 3rd party engineers, that a dam re-build is required to return the facility to operation. The Generation Group is currently evaluating environmental permitting and rebuild scenarios. Consequently, the Generation Group does not anticipate any near-term expenditures related to Bill C-93 compliance of the existing structure.

In addition to the Bill C-93 related dam remediation work, the Generation Group 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 for APUC, the Generation Group and the Distribution Group 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 operating groups as at December 31, 2014 under the Facilities:

	As at December 31, 2014				As at Dec 31 2013
(all dollar amounts in $ millions)	Corporate	Generation Group	Distribution Group	Total	Total
Committed Facilities	$ 65.0	$ 350.0	$ 232.0	$ 647.0	$ 477.7
Funds drawn on Facilities	—	(23.4)	(23.9)	(47.3)	(210.2)
Letters of Credit issued	(10.8)	(96.0)	(7.0)	(113.8)	(64.9)
Funds available for draws on the Facilities	**$ 54.2**	**$ 230.6**	**$ 201.1**	**$ 485.9**	$ 202.6
Cash on Hand				9.3	13.8
Total liquidity and capital reserves	**$ 54.2**	**$ 230.6**	**$ 201.1**	**$ 495.2**	$ 216.4

As at December 31, 2014, the Company's $65.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility"), was undrawn and had $10.8 million of outstanding letters of credit. The facility matures on November 19, 2016 and is subject to customary covenants.

As at December 31, 2014, the $350.0 million Generation Credit Facility had drawn $23.4 million and had $96.0 million in outstanding letters of credit. On July 31, 2014, the Generation Group increased the credit available under its credit facility to $350 million from $200 million. The larger credit facility will be used to provide additional liquidity in support of the group's $1,225.0 million development portfolio to be completed over the next four years. In addition to the larger size, the maturity of the credit facility has been extended from three to four years extending to July 31, 2018.

As at December 31, 2014, the Distribution Group's $232.0 million (U.S. $200.0 million) senior unsecured revolving credit facility (the "Distribution Credit Facility") had drawn $23.9 million (U.S. $20.6 million) and had $7.0 million (U.S. $6.0 million)of outstanding letters of credit. The facility matures on September 30, 2018 and is subject to customary covenants

Long Term Debt

On January 17, 2104, the Generation Group issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "Generation Debentures") pursuant to a private placement in Canada and the United States. The Generation Debentures were sold at a price of $99.864 per $100.00 principal amount resulting in an effective yield of 4.67%. Concurrent with the offering, the Generation Group entered into a fixed for fixed cross currency swap, coterminous with the Generation Debentures, to economically convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of approximately 4.77%.

On December 31, 2014, the U.S. $19.2 million senior debt for the Sanger Thermal Facility was repaid.

As at December 31, 2014, the weighted average tenor of APUC's total long term debt is approximately 8.0 years with an average interest rate of 4.9%.

Contractual Obligations

Information concerning contractual obligations as of December 31, 2014 is shown below:

(all dollar amounts in $ millions)		Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Long-term debt obligations	$	1,280.0	9.1	91.0	218.8	961.1
Advances in aid of construction	$	81.1	1.1	—	—	80.0
Interest on long-term debt obligations	$	438.3	64.2	125.3	102.1	146.7
Purchase obligations	$	267.9	267.9			
Environmental obligation	$	72.6	19.6	36.6	6.1	10.3
Derivative financial instruments:						
Cross currency swap	$	36.3	1.5	3.0	2.4	29.4
Interest rate forward	$	4.7	—	—	4.7	—
Interest rate swap	$	1.4	1.4	—	—	—
Energy derivative contracts	$	2.9	2.3	0.6	—	—
Purchased power	$	118.2	118.2	—	—	—
Gas delivery, service and supply agreements	$	264.3	52.8	68.0	55.3	88.2
Long term service agreements	$	637.3	28.6	64.7	62.9	481.1
Capital projects	$	22.0	22.0	—	—	—
Operating leases	$	121.1	5.6	9.6	8.5	97.4
Other obligations	$	40.5	9.9	0.9	—	29.7
Total obligations	$	**3,388.6**	$ **604.2**	$ **399.7**	$ **460.8**	$ **1,923.9**

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at December 31, 2014, APUC had 238,149,468 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.

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

On December 11, 2014, APUC completed a public offering of 10,055,000 common shares at a price of $9.95 per share, for gross proceeds of approximately $100.0 million.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2014, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon Wind Energy LP; and
- 4,000,000 cumulative rate reset Series D preferred shares, yielding 5.0% annually for the initial five-year period ending on March 31, 2019.

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of shares of APUC. As at December 31, 2014, 63.8 million common shares representing approximately 27% of total shares outstanding had been registered with the Reinvestment Plan and 2,262,885 shares were issued during the year ended December 31, 2014. During the quarter ended December 31, 2014, 665,172 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on January 15, 2015, an additional 706,680 common shares were issued under the Reinvestment Plan.

Emera subscription receipts

For the year ended December 31, 2014, APUC did not issue any common shares to Emera.

On October 7, 2014, the Company issued 8,708,170 Subscription Receipts of APUC at a purchase price of $8.90 per Subscription Receipt for an aggregate subscription price of $77.5 million. The investment was made under the Strategic Investment Agreement between Emera and APUC, in support of the acquisition by APUC of the Odell Wind Project in Minnesota (the "Odell Acquisition"). The proceeds of the subscription are intended to be used by APUC to partially finance the Odell Acquisition and the completion of the Odell Wind Project. Subject to adjustments as provided in the applicable subscription agreement, Emera may convert the Subscription Receipts into common shares of APUC on a one-for-one basis on November 14, 2015 (the first anniversary of the closing of the Odell Acquisition) or the commercial operation date of the Odell Wind Project, whichever is first to occur.

On December 2, 2014, the Corporation issued 3,316,583 subscription receipts of APUC at a purchase price of $9.95 per subscription receipt for an aggregate subscription price of $33.0 million. The investment was made under the Strategic Investment Agreement between Emera and APUC, in support of the acquisition by APUC of the Park Water Company in Montana (the "Park Water Acquisition"). The proceeds of the subscription are intended to be used by APUC to partially finance the Park Water Acquisition. Subject to adjustments as provided in the applicable subscription agreement, Emera may convert the Subscription Receipts into common shares of APUC on a one-for-one basis on December 29, 2015 (the first anniversary of the closing of the subscription transaction) or the closing of the Park Water Acquisition, whichever is first to occur.

Conversion of the aforementioned Subscription Receipts into common shares is conditional on Emera's holdings not exceeding 25% of the outstanding common shares of APUC at the time of conversion.

As at March 15, 2015, in total, Emera owns 50,126,766 APUC common shares representing approximately 21.0% of the total outstanding common shares of the Company, and there are 12,024,753 subscription receipts currently held by Emera. 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, 2014, APUC recorded $1.1 million and $3.2 million, respectively, in total share-based compensation expense, as compared to $0.6 million and $2.0 million, respectively, for the same period in 2013. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2014, total unrecognized compensation costs related to non-vested options and share unit awards were $2.1 million and $2.4 million, respectively, and are expected to be recognized over a period of 1.71 and 1.61 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.

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. During the year, the Company issued 969,998 options to employees of the Company.

As at December 31, 2014, a total of 5,537,127 options had been issued and outstanding under the plan.

Performance Share Units

APUC issues performance share units ("PSUs") to certain members of management other than senior executives as part of APUC's long-term incentive program. The PSUs provide for settlement in cash or shares at the election of APUC.

During the year, the Company settled 11,406 vested PSUs for $0.2 million in cash. The plan provides for settlement in cash or shares at the election of the Company. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Company expects to settle the remaining PSUs in shares. As a result, the PSUs continue to be accounted for as equity awards. During the year, the Company issued 407,962 PSUs to executives and employees of the Company.

As at December 31, 2014, a total of 440,086 PSU's have been granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSU's in cash, these DSUs are accounted for as equity awards. During the year, the Company issued 35,455 DSUs to the directors of the Company.

As at December 31, 2014, a total of 110,241 DSUs had been granted under the DSU plan.

Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the year, the Company issued 93,598 common shares to employees under the ESPP plan.

As at December 31, 2014, a total of 240,411 shares had been issued under the ESPP.

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt and equity levels, at its individual operating groups and at an overall company level.

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 appropriately sized revolving credit facilities available for ongoing investment in growth and 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 groups are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

Ian Robertson and Chris Jarratt ("Senior Executives"), respectively Chief Executive Officer and Vice-Chair of APUC, are indirect shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of the Company and several related affiliates (collectively the "Parties"). Prior to 2010, there were several related party transactions and co-owned assets which existed pursuant to the external management structure before the internalization of management which occurred on December 21, 2009.

In 2011, the Board formed an independent committee ("Independent Board Committee") and initiated a process to review all of the remaining business associations with the Parties in order to reduce and/or eliminate these relationships. The Independent Board Committee engaged independent consultants and advisors to assist with this process and to provide advice in respect thereof. Specifically, the independent advisors provided advice to the Independent Board Committee in relation to the valuations of the generating assets, tax and legal matters.

The process, initiated in 2011, was completed in November 2013 and all related party transactions, except as noted below, between APUC and the Parties have been addressed to the satisfaction of the Independent Board Committee and the Board as discussed below.

The following describes the business associations and resolution with APMI and Senior Executives:

Due to and from related parties

Effective December 31, 2013, APUC paid the Parties $1.8 million in connection with outstanding fees and the Parties paid APUC $0.8 million in connection with reimbursement of expenses. As at December 31, 2014, $0.047 million (2013 - $0.047 million) remains due from Algonquin Power Systems Ltd., a corporation partially owned by the Senior Executives.

Equity interests in Rattle Brook Hydro, Long Sault Hydro, and BCI Thermal Facilities

The Parties own interests in three power generation facilities in which APUC also has an interest. A brief description of the facilities is provided as follows:

- Rattle Brook is a 4 MW hydroelectric generating facility ("Rattle Brook") constructed in 1998 in which APUC owns a 45% interest and Senior Executives hold an equity interest in the remaining 55%.
- Long Sault Hydro Facility is an 18MW hydroelectric generating facility constructed in 1997. APUC acquired its interest in Long Sault Hydro Facility by way of subscribing to two notes from the original partners. One of the original partners, an affiliate of APMI, is entitled to receive 5% of the equity cash flows commencing in 2014.
- Brampton Cogeneration ("BCI Thermal Facility") is an energy supply facility which sells steam produced by EFW. In 2004, APMI acquired 50 Class B partnership units in BCI Thermal Facility entitling them to 50% of the cash flow above 15% return on the investment.

Effective December 31, 2013, APUC acquired the Parties' shares of Algonquin Power Corporation Inc. ("APC") which owns the partnership interest in the 18MW Long Sault Hydro Facility and the partnership interest in the BCI Thermal Facility plant for an amount equal to $3.8 million. As APUC already consolidates Long Sault Hydro Facility as a VIE, the acquisition of this partnership interest was treated as an equity transaction. The payment resulted in an adjustment to deferred tax liability of $10.7 million in regards to tax attributes acquired with the partnership interests and an adjustment of $14.6 million to equity of the shareholders of the Company as the partnership interests had a nominal carrying amount prior to the exchange.

In addition, APUC sold its 45% interest in the 4 MW Rattle Brook Hydro Facility to the Parties for gross proceeds $3.4 million for a loss on sale, net of tax of $0.4 million.

APUC earned a fee of $0.4 million from APC during the year ended December 31, 2013 related to settlement of the related party transactions.

St. Leon LP Units

Third party investors, including Senior Executives, previously held 100 Class B limited partnership units issued by the St. Leon Limited Partnership, which is the legal owner of the St. Leon Wind Facility.

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B units (note 11) including 36 units held indirectly by Senior Management. The Series C preferred shares provide dividends identical to what is expected from the Class B units, as determined by independent consultants retained by the Independent Board Committee. As of January 1, 2013, no Senior Executives have any further direct or indirect ownership of the St. Leon Wind Facility.

Office Facilities

APUC has leased its head office facilities since 2001 on a triple net basis from an entity partially owned by the Senior Executives. Base lease costs for the year ended December 31, 2014 were $0.3 million (2013 - $0.3 million). In the fourth quarter of 2014, APUC moved all head office employees into new premises and terminated the related party lease for nominal consideration. There is no further related party matter in relation to an office lease.

Chartered Aircraft

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into an agreement to charter aircraft in which the Senior Executives have a partial ownership. During the year ended December 31, 2013, APUC reimbursed direct costs in connection with the use of the aircraft of $0.5 million. As at December 31, 2013, the Independent Board Committee and the Parties agreed that all future utilization of chartered aircraft would be undertaken through a third-party charter operator at fair market value and under arrangements in which the Senior Executives have no interest. Final arrangements in this regard had not been completed as at December 31, 2014. During the year ended December 31, 2014, APUC reimbursed direct costs in connection with the use of the aircraft of $0.7 million.

Trafalgar

The Company owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, Trafalgar went into default under its debt obligations and an affiliate of APMI moved to foreclose on the assets. Subsequently, Trafalgar went into bankruptcy. APUC and the affiliate of APMI have been jointly involved in litigation and in bankruptcy proceedings with Trafalgar since 2004. APMI initially funded $2.0 million in legal fees prior to 2004.

In 2004, the Board reimbursed APMI $1.0 million of the total third party legal fees (which to that point totalled $2.0 million), and APUC agreed to fund future legal fees, third party costs and other liabilities. It was agreed that any net proceeds from the lawsuits would be shared proportionally to the quantum of net costs funded by each party.

A member of the Board is an executive at Emera. Related Party Transactions between APUC and Emera are discussed below:

- For the year ended December 31, 2014, the Company sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $5.8 million (2013 - U.S. $6.0 million). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3.0 million and a letter of credit in an amount of U.S. $0.1 million, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine. For the year ended December 31, 2014, the Company purchased natural gas amounting to U.S. $5.0 million (2013 - U.S. $1.3 million) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction.
- In 2011, APUC provided a corporate guarantee in an amount of U.S. $1.0 million to a subsidiary of Emera providing lead market participant services for fuel capacity and forward reserve markets to ISO NE for the Windsor Locks Thermal Facility. There has not been any transaction under this contract in the last three years.

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

Other

A spouse of one of the Senior Executives provided market research consulting services to certain subsidiaries of the Company. During the year ended December 31, 2014, APUC paid $0.192 million (2013 - $0.045 million) in relation to these services.

ENTERPRISE RISK MANAGEMENT

An enterprise risk management ("ERM") framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of our objectives. APUC's ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization.

As part of the risk management processes, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by APUC's internal ERM team. Key risks and associated mitigation strategies are reviewed by the Executive Risk Steering Committee on a monthly basis and presented to the Board of Directors on a quarterly basis. The key risk categories assessed include: safety, environment, natural disasters, security (physical and cyber), operations, organizational effectiveness, contracts, budget, capital projects, return on M&A activity, markets, liquidity, financial reporting, strategic, and regulatory.

Risks are assessed consistently across the organization using a common risk matrix to assess impact and likelihood. Financial, reputation and safety implications are considered when determining the impact of a potential risk. Risk treatment priorities are established based upon these risk assessments and incorporated into the development of APUC's strategic plans.

The development and execution of risk treatment plans are actively monitored by the ERM team through a centralized risk register software application. APUC's internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for the key risks. Audit findings are discussed with business owners and reported to the Board audit committee on a quarterly basis. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, Executive Risk Steering Committee, and the Board of Directors for consideration.

APUC's ERM framework follows the guidance of ISO 31000;2009. The Board oversees management to ensure the risk governance structure and risk management processes are robust, and that APUC's risk appetite is thoroughly considered in decision-making across the organization.

The risks discussed below are not intended as a complete list of all exposures that APUC is encountering or may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the most recent AIF.

Treasury Risk Management

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 78% of EBITDA in 2014 and 77% 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 $22.8 million ($0.10 per share) on an annual basis.

In light of the currency profile of its operations, APUC changed the currency of its dividend to U.S. dollars in the third quarter of 2014. APUC further manages currency risk through the matching of U.S. long term debt to finance its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing cost. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes. APUC may from time to time enter into short term foreign currency derivative contracts to hedge exposure of anticipated transactions denominated in a foreign currency.

Market Price Risk

The Distribution Business Group is not exposed to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

The Generation Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the Generation Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Company is not able to generate the specified amount of power at the specified time resulting in production shortfalls under the hedge that then requires the Company to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Generation Group generally seeks to structure hedges to cover less than 100% of the anticipated production, thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to mechanical failures, production shortfalls may be such that the Generation Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

Hedges currently put in place by the group along with residual exposures to the market are detailed below:

On May 15, 2012, the Generation Group entered into a financial hedge, which expires December 31, 2016, with respect to its Dickson Dam Hydro Facility located in the Western region. The financial hedge is structured to hedge 75% of the facility's expected production volume against exposure to the Alberta Power Pool's current spot market rates. The annual unhedged production based on long term projected averages is approximately 16,000 MW-hrs annually. Therefore, each U.S. $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of U.S. $0.2 million on an annualized basis.

The July 1, 2012 acquisition of Sandy Ridge Wind Facility included a financial hedge, which commenced on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 44,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market prices would result in a change in revenue of about U.S. $0.4 million for the year.

The December 10, 2012 acquisition of Senate Wind Facility included a physical hedge, which commenced on January 1, 2013 for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility's expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market prices would result in a change in revenue of about U.S. $1.9 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of about U.S. $1.9 million for the year.

Under each of the above noted hedges, if production is not sufficient to meet the unit quantities under the hedge, the shortfall must be purchased in the open market at market rates. The effect of this risk exposure cannot be quantified as it is dependent on both the amount of shortfall and the market price of electricity at the time of the shortfall.

In addition to the above noted hedges, from time to time the Generation Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2014, the Generation Group had not entered into any such hedges.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on January 1, 2013 for a 20 year period. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production based on expected long term average production, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of about U.S. $0.5 million for the year.

Credit/Counterparty Risk

APUC and its subsidiaries are subject to credit risk through its long term power purchase contracts, 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 the credit risk of default by counterparties to its long term power purchase contracts to be significant, as approximately 84.7% of the Generation Group's revenues are earned from large utility customers having a credit rating of Baa1 or better by Moody's Rating Services or BBB+ or higher by S&P Rating Services. The following chart sets out the Generation Group's significant customers, their credit ratings and percentage of total revenue associated with the customer:

Counterparty	Credit Rating [1]		Approximate Annual Revenues	Percent of Divisional Revenue
Generation Group - Renewable Energy				
PJM Interconnection LLC	Aa3		49.0	33.6%
Manitoba Hydro	Aa1		31.1	21.4%
Hydro Quebec	Aa2		22.6	15.5%
Ontario Electricity Financial Corporation	Aa2		17.8	12.2%
Emera Maine [2]	N/A		8.0	5.5%
Total – Renewable Energy		**$**	**128.5**	**88.2%**
Generation Group - Thermal Energy				
Pacific Gas and Electric Company	Baa1		19.8	46.1%
Connecticut Light and Power	Baa1		23.2	53.9%
Total – Thermal Energy		**$**	**43.0**	**100.0%**
Total – Generation Group		**$**	**171.5**	**84.7%**

1 Ratings by Moody's or Standard & Poor's as of February 2015.

2 Maine Public Service is a subsidiary of Emera which has a corporate rating of BBB+.

The remaining revenue is primarily earned by the Distribution Group. In this regard, the credit risk attributed to the Distribution Group's accounts receivable balances at the water and wastewater distribution systems total U.S. $5.9 million which is spread over approximately 97,000 connections, resulting in an average outstanding balance of approximately $60 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $62.0 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. 24.3 million. The natural gas and electrical utilities, respectively, derive over 91% and 87% of their revenue from residential customers.

In addition to the counterparty risk related to customer sales outlined above, the Generation and Distribution Groups utilize 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. The company manages 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:

- The Corporate Credit Facility is subject to a variable interest rate. The APUC Facility has no amounts outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.

- The Generation Credit Facility had $23.4 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Distribution Credit Facility had $23.9 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Generation Group is party to an interest rate swap whereby the group pays a fixed interest rate of 4.47% on a notional amount of $60.5 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. 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. As a result, a 100 basis point change in the variable rate would impact derivative gains/losses by $0.01 million.
- The Shady Oaks Senior Debt Facility had $88.2 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.9 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. The interest rate swap, although not designated as a hedge, serves to partially offset interest rate movements against the variable pay portion of the Company's debt.

To mitigate refinancing risk, from time to time APUC may seek to fix interest rates on expected future financings. In the fourth quarter, the Generation Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment will apply to this transaction. Consequently, changes in fair value, to the extent deemed effective, will be recorded into Other Comprehensive Income.

Tax Risk and Uncertainty

Although APUC is of the view that all expenses being claimed by APUC are reasonable and that the cost amount of APUC's depreciable properties have been correctly determined, there can be no assurance that the Canada Revenue Agency or the Internal Revenue Service will agree. A successful challenge by either agency regarding the deductibility of such expenses or the correctness of such cost amounts could impact the return to shareholders.

Unit Exchange Transaction

On October 27, 2009, unitholders of Algonquin Power Income Fund exchanged their trust units on a one for one basis for common shares of Algonquin Power & Utilities Corp (the "Unit Exchange Transaction"). As a result of the Unit Exchange Transaction, APUC recorded certain additional tax attributes to the extent management believed they were more likely than not to be realized. The excess of the carrying amount of the tax attributes assumed over the consideration paid was recorded as a deferred credit of $55.6 million on the date of the Unit Exchange Transaction (the "Transaction Date"). The deferred credit has been recognized into income as a deferred income tax recovery in relative proportion to the amount of the related tax attributes that have been utilized since the Transaction Date.

Subsequent to the Balance Sheet date, APUC received a proposal letter from the Canada Revenue Agency ("CRA") which outlines its intention to challenge the tax consequences of APUC's 2009 Unit Exchange. CRA is seeking to apply the acquisition of control rules or the general anti-avoidance rules of the Income Tax Act (Canada) the effect of which would be to deny APUC of the benefit of the tax attributes assumed as part of the Unit Exchange Transaction.

Should APUC receive a Notice of Reassessment covering the 2009, 2010, 2011, 2012 and 2013 taxation years, APUC will be required to make a deposit payment of 50% of the tax liability (including interest and any applicable penalties) claimed by the CRA in order to appeal the expected reassessment. Based on the tax amounts related to the 2009 to 2013 taxation years, that payment amount would be approximately $17.5 million. Additionally, assuming the 2014 taxation year will be similarly reassessed, a further payment of approximately $3.1 million would also be required. APUC would also be required to make a deposit payment of 50% of the taxes the CRA claims are owed in any future tax year if the CRA were to issue a similar notice of reassessment for such years and APUC were to appeal it.

Should APUC be successful in defending its position, all such payments plus applicable interest, will be refunded to APUC. If the CRA is successful, APUC will be required to pay the balance of the taxes assessed (plus applicable interest and any applicable penalties).

APUC has 90 days from the date of any Notice of Reassessment to prepare and file a Notice of Objection, which would be reviewed by the CRA's appeals division. If the CRA appeals division does not allow APUC's initial appeal, APUC has the option to file its case with the Tax Court of Canada. APUC anticipates that legal proceedings through the various tax courts could take approximately two to four years.

APUC remains confident in the appropriateness of its tax filing position and the expected tax consequences of the Unit Exchange Transaction and intends to vigorously defend such position. APUC strongly believes that the acquisition of control or the general anti-avoidance rules do not apply to the Unit Exchange Transaction and intends to file its future tax returns on a basis consistent with its previous tax returns. As a result, the probability of any potential final cash payment and impact on net earnings cannot be estimated at this time, but could range from $nil to $45.0 million.

The impact of the proposal on APUC's tax provision has been considered by management; however, management continues to believe that the most likely outcome has not changed and it is more likely than not, that APUC will be successful in defending its position. On this basis, APUC's 2014 financial statements do not include the impact of a potential reassessment. Until the matter is resolved with CRA, or should new facts arise that would result in a change to management's assessment of the most likely outcome, any future deposit tax payments made by APUC will be recorded to the balance sheet and will not impact either adjusted funds from operations or net earnings.

On a consolidated basis, APUC and its Canadian subsidiaries have tax attributes that are available to reduce or eliminate cash taxes. Should the CRA ultimately be successful in the appeal process, APUC will seek to refile prior year tax returns and accelerate the use of such tax attributes to minimize any actual cash taxes that would otherwise be owed as a result of the reassessment of the tax consequences of the Unit Exchange.

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 the Generation Group and the Distribution Group 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 to meet liabilities when due.

As at December 31, 2014, APUC and its subsidiaries had a combined $485.9 million of committed and available revolving credit facilities remaining and $9.3 million of cash resulting in $495.2 million of total liquidity and capital reserves.

APUC currently pays a dividend of U.S. $0.35 per common share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements, and to fund working capital that, in its judgment, ensures APUC's long-term success. Based on the level of common share dividends paid during the year ended December 31, 2014, cash provided by operating activities exceeded common share dividends declared by 2.2 times and Adjusted Cash From Operations exceeds common share dividends by 3.4 times.

The current and long term portion of debt totals approximately $1,280.0 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

The Generation Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Distribution Groups is exposed to energy and natural gas price risks at its electric and natural gas systems. In this regard, a discussion of this risk is set out as follows:

- The Sanger Thermal 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.
- The Windsor Locks Thermal Facility's Energy Services Agreement includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. 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.
- The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 174,000 MW-hrs in fiscal 2015, of which 90,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 80,000 MW-hrs of its energy requirements at the ISO-NE summer spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 174,000 MW-hrs. The risk associated with the expected market purchases of 80,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 90% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $65 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.5 million on an annualized basis.

The CalPeco Electric System provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the CPUC. The CalPeco Electric System purchases the energy, capacity, and related service requirements for its customers from NV Energy via a PPA at rates reflecting NV Energy's system average costs.

The CalPeco Electric System's tariffs allow for the pass-through of energy costs to its rate payers on a dollar for dollar basis, through the energy cost adjustment clause ("ECAC") mechanism, which allows for the recovery or refund of changes in energy costs that are caused by the fluctuations in the price of fuel and purchased power. On a monthly basis, energy costs are compared to the CPUC approved base tariff energy rates and the difference is deferred to a balancing account. Annually, based on the balance of the ECAC balancing account, if the ECAC revenues were to increase or decrease by more than 5%, the CalPeco Electric System's ECAC tariff allows for a potential adjustment to the ECAC rates which would eliminate the risk associated with the fluctuating cost of fuel and purchased power. The CalPeco Electric System also benefits from a revenue decoupling mechanism and a vegetation management memorandum account. The revenue decoupling mechanism decouples 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.

The Granite State Electric System 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, Granite State Electric System provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for all customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System's Default Service customers. Since this is a full requirements service, the winning bidder take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

The EnergyNorth Natural Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties. The EnergyNorth Natural Gas System's portfolio of assets and its planning and forecasting methodology are approved by the NHPUC bi-annually through an Integrated Resource Plan filing. In addition, EnergyNorth Natural Gas System files with the NHPUC for recovery of its transportation and commodity costs through a semi-annual basis through the Cost of Gas ("COG") filing and approval process. The EnergyNorth Natural Gas System establishes rates for its customers based on the NHPUC approval of its filed COG. These rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the EnergyNorth Natural Gas System locks in a fixed price basis for approximately 14% of its normal winter period purchases under a NHPUC approved hedging program. All costs associated with the fixed basis 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, the EnergyNorth Natural Gas System 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 interest to the next year's period COG filing, i.e. winter to winter and summer to summer.

The 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. The Midstates Gas Systems 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, the Company 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. Rates can be adjusted 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

Mechanical and Operational Risks

APUC's profitability could be impacted by, among other things, 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 Generation Group's hydro assets utilize dams to pond water for generation and if the dams burst potentially catastrophic amounts of water would flood downriver from the facility. The dams can be subjected to drought conditions and lose the ability to generate during peak load conditions, causing the facilities to fall short of either hedged or PPA committed production levels. The risks of the hydro facilities are mitigated by regular dam inspections and a maintenance program of the facility to lessen the risk of dam failure.

The Generation Group's wind assets could on catch on fire and, depending on the season, could ignite significant amounts of forest or crop downwind from the wind farms. The wind units could also be affected by large atmospheric conditions (e.g. El Nina), which will lower wind levels below our PPA and hedge minimum production levels. Production risks associated with the wind turbine generators is mitigated by properly maintaining the units using long term maintenance agreements with the turbine O&M's, which provide for regular inspections and maintenance of property and liability insurance policies. Icing can be mitigated by shutting down the unit as icing is detected at the site.

The Generation Group's Thermal Energy Division uses natural gas and oil, and produce exhaust gases, which if not properly treated and monitored could cause hazardous chemicals to be released into the atmosphere. The units could also be restricted from purchasing gas/oil due to either shortages or pollution levels, which could hamper output of the facility. The mechanical and operational risks at the Thermal Energy Division are mitigated through the regular maintenance of the boiler system, and by continual monitoring of exhaust gases. Fuel restrictions can be hedged somewhat by long term purchases.

All of the Generation Group's renewable and thermal generating stations are subject to mechanical breakdown. The risk of mechanical breakdown is mitigated by properly maintaining the units and by regular inspections.

The Distribution Group's water and wastewater distribution systems 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 Distribution Group's electric distribution systems 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 Distribution Group's natural gas distribution systems are subject to risks which may lead to fire and/or explosion which may impact life and property. Risks include third party damage, compromised system integrity, type/age of pipelines, and severe weather events.

These risks are mitigated through the diversification of APUC's operations, both operationally (the Generation and Distribution Groups) and geographically (Canada and U.S.), the use of regular maintenance programs, including pipeline safety programs and compliance programs, and maintaining adequate insurance and the establishment of reserves for expenses.

Regulatory Risk

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

The Distribution Group's 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. As a strategy to mitigate, the Distribution Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expense. A fundamental risk faced by any regulated utility is the disallowance of costs to be placed into its revenue requirement by the utility's regulator. To the extent proposed costs are not allowed into rates, the utility will be required to find other efficiencies or cost savings to achieve its allowed returns.

The Distribution Group regularly works with its governing authorities to manage the affairs of the business employing both local state level and corporate resources.

Condemnation Expropriation Proceedings

The Distribution Group's electricity and natural gas distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require just and fair compensation be paid to the Distribution Group and the Distribution Group believes such compensation would reflect fair market value for any assets that are taken. Notwithstanding the determination of such fair and just compensation will be undertaken pursuant to a legal proceeding and therefore there is no assurance that the value received for assets taken will be in excess of book value. In 2014, the Company entered into an agreement to acquire the regulated water distribution utility Park Water Company. The Park Water Company owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Mountain Water Company is the water utility in Western Montana serving the municipality of Missoula owned by Park Water Company. Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the city of Missoula will be successful in its condemnation efforts. If the city of Missoula is successful in its condemnation efforts, the quantum of compensation to be paid by the city of Missoula for such taking will be subsequently determined by a valuation hearing by the courts. In respect of such potential valuation hearing, expert reports have been prepared by Mountain Water Company which indicate a fair value of Mountain Water Company of between US $116.0 million and US$141.0 million.

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 ability to quantify such expense, the timing of incurring the potential expenses, as well as other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

The Distribution Group's 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, the Distribution Group has regular programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These costs can generally be included in the facility's rate base and thus the Distribution Group expects to be allowed to earn a return on such investment.

In conjunction with recent acquisitions and developed projects, the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements for: (i) removal of wind 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 an adequate insurance program, which includes property, equipment breakdown, environmental, and liability policies.

The Generation Group's ongoing operations and historic activities are subject to various environmental laws and regulations and are regulated by federal agencies such as the United States Environmental Protection Agency, Federal Energy Regulatory Commission ("FERC"), NERC, Environment Canada, Fisheries and Oceans Canada; and State/Provincial Agencies, such as the New York State Department of Environmental Conservation ("NYSDEC"), California Air Resource Board, Connecticut Department of Environmental Protection ("CDEP"), Illinois Department of Environmental Protection ("IDEP'), Pennsylvania Game Commission ("PGC"), Alberta Environment, Manitoba Conservation, Ontario Ministry of the Environment, Ontario Ministry of Natural Resources, among others. Power generation facilities generate air emissions, noise, potential for flooding, spill risk, possible disruption of protected wildlife, along with the generation of industrial wastewater and certain amounts of hazardous wastes.

The Distribution Group 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, the Distribution Group 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, the Generation and Distribution Groups investigate 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 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. Natural Gas Distribution Systems are subject to detailed inspections by State Regulatory Agencies to ensure adherence to applicable regulations. State Regulator Agencies review the Company's policies in reference to operation and maintenance, construction, training, emergency response, reporting, contractor management and measurements. The Distribution Group monitors all aspects of pipeline safety and quickly mitigates any identified concerns.

The primary risks associated with the operation of power generation facilities are related to uncontrolled contaminant releases (or above the permitted limits), not being in continued compliance with permits and licenses obligations such as, continuous emissions monitoring, periodic reporting/source testing, general performance/operating conditions, operations adjustments (wind projects) resulting from post construction wildlife mortality monitoring, dam safety, potential accidental release of mineral oil or other hazardous materials to the environment.

The Distribution Group'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, 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 the Distribution Group, the EnergyNorth Gas Utility, the Granite State Electric Utility, and the New England Gas System were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Distribution Group 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 Distribution Group 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 Distribution Group estimates the remaining undiscounted and unescalated cost of these MGP-related environmental cleanup activities will be $72.6 million which, at discount rates ranging from 2.1% to 3.4%, represents $72.3 million on a discounted basis, as the Distribution Group's estimate of costs for known issues that has been accrued at December 31, 2014. By rate orders, the Regulator provided for the recovery of site investigation and remediation costs and accordingly, at December 31, 2014 the Company has reflected a regulatory asset of $102.7 million 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.

Cycles and Seasonality

Generation Group

The Generation Group's hydroelectric operations are impacted by seasonal fluctuations and year to year variability of the available hydrology. 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. Year to year the level of hydrology varies impacting the amount of power that can be generated in a year.

The Generation Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the spring and fall periods, winds are generally stronger than during the summer periods. The ability of these facilities to generate income may be impacted by naturally occurring changes in wind patterns and wind strength.

The Generation Group's solar generation facilities are impacted by seasonal fluctuations and year to year variability in the solar radiance. For instance, there are more daylight hours in the summer than there are in the winter resulting in higher production in the summer months. The ability of these facilities to generate income may be impacted by naturally occurring changes in solar radiance.

The Company attempts to mitigate the above noted natural resource fluctuation risks by acquiring or developing generating stations in different geographic locations.

Distribution Group

The Distribution Group'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.

The Distribution Group's demand for energy from its electric distribution systems is primarily affected by weather conditions and conservation initiatives. The Distribution Group 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.

The Distribution Group's primary demand for natural gas from its natural gas distribution systems is driven by the seasonal heating requirements of its residential, commercial, and industrial customers. The colder the weather the greater the demand for natural gas to heat homes and businesses. As such, the natural gas distribution systems demand profiles typically peaks in the winter months of January and February and declines in the summer months of July and August. Year to year variability also occurs depending on how cold the weather is in any particular year.

The Company attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, at the Peach State Gas System in Georgia, a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns.

Not all regulatory jurisdictions in which the Distribution Group operates have approved mechanisms to mitigate demand fluctuations.

Development and Construction Risk

The Generation Group actively engages in the development and construction of new power generation facilities. The current pipeline of projects either currently in construction or in development is $1.2 billion and are mainly renewable solar and wind projects. There is always a risk that material delays and/or cost overruns could be incurred in any of the projects planned or currently in construction affecting the company's overall performance. Examples of inherent risks pertaining to power generation facility development can include: technical issues with the interconnection utility, unfavorable permitting results or delays emanating from State, Provincial or Federal agency interface, construction delays or cost overruns, equipment performance outside of expectations, and land owner disputes. The Generation Group mitigates these risk through its due diligence processes, sound project management principals and appropriate contingency plans and reserves.

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 wind 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.

The amount of solar radiance will vary from the estimate set out in the initial solar studies that were relied upon to determine the feasibility of the solar facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the solar radiance, 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.

For certain of its development projects, the Generation Group relies on financing from third party Tax Equity Investors. These investors typically provide funding upon commercial operation of the facility. Should certain facilities not meet the conditions required for tax equity funding, expected returns from the facilities may be impacted.

Obligations to Serve

The Distribution Group 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, the Distribution Group may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

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.

Trafalgar Proceedings

Trafalgar commenced an action in 1999 in U.S. District Court against APUC, and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to APUC and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the "Trafalgar Hydro Facilities"). In 2001, Trafalgar and other entities also filed for Chapter 11 reorganization in bankruptcy court and also filed a multi-count adversary complaint against certain subsidiary entities of APUC, which complaint was then transferred to the District Court. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the Trafalgar Class B Note, that APUC was therefore the holder and owner of the Trafalgar Class B Note, and that all other claims by Trafalgar with respect to the transfer of the Trafalgar Class B Note were without merit. Further, on November 6, 2008, the claims that were remaining in the District Court against APUC were dismissed by summary judgment. On October 22, 2009, Trafalgar filed an appeal from the November 6, 2008 summary judgment to the United States Court of Appeals for the Second Circuit. As discussed further below, as the proceedings continued, the United States Second Circuit Court of Appeals, among other things, (i) on November 2, 2010 dismissed the claims against APUC in the civil proceedings; and (ii) on January 30, 2013, held that Algonquin has a security interest in Trafalgar's engineering malpractice claim and its proceeds.

With respect to the civil proceedings, the United States Second Circuit Court of Appeals dismissed all the claims against APUC 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 filed a notice of appeal of the Memorandum-Decision and Order. The appeal was argued on March 21, 2013. On March 25, 2013, the United States Second Circuit Court of Appeals affirmed the decision of the District Court giving APUC judgment on its claims. Trafalgar asked the United States Second Circuit Court of Appeals for reconsideration of its decision or to certify a legal question to the Connecticut Supreme Court. On May 21, 2013, the United States Second Circuit Court of Appeals denied Trafalgar's petition and the matter was sent back to the District Court for further proceedings with respect to the enforcement of APUC's remedies under the loan documents, including the calculation of the debt and the disposition of collateral. The District Court entered judgment in favor of APUC with regard to the default and APUC's entitlement to recourse to the collateral, but without determining the amount due under the note. The District Court then closed the case.

With respect to the bankruptcy proceedings, on January 30, 2013, the United States Second Circuit Court of Appeals held that Algonquin did have a security interest in Trafalgar's engineering malpractice claim and its proceeds. On February 20, 2013, Trafalgar filed a petition for a rehearing with the United States Second Circuit Court of Appeals, and in the alternative, sought to have the Second Circuit certify a legal question to the New York State Court of Appeals. The Second Circuit denied the petition and certification request which petition was denied on June 17, 2013. On September 16, 2013, Trafalgar filed a Petition for a Writ of Certiorari with the United States Supreme Court. Algonquin filed a brief in opposition to the Petition on October 18, 2013. On December 2, 2013, the United States Supreme Court denied Trafalgar's petition for a Writ of Certiorari. Algonquin filed and served a motion seeking an order terminating the automatic stay and directing the distribution of the funds held in the escrow account to Algonquin. Algonquin's motion for relief from the automatic stay has been denied without prejudice to re-filing the motion after the court determines the amount of Algonquin's claim and the validity of any defenses to the claim. Algonquin and Trafalgar have each filed motions with the Court seeking a determination of those issues. Those motions are under consideration by the Court.

The Court has approved the sale of all seven of the Trafalgar facilities. Of the seven, one has closed while the other six is anticipated to close upon obtaining regulatory approval. The parties are attempting to resolve this matter through good faith settlement negotiations.

Côte Ste-Catherine Water Lease Dues

On December 19, 1996, the Attorney General of Québec (the "Québec AG") filed suit in Québec Superior Court against Algonquin Dévelopment (Côte Ste-Catherine) Inc. (Dévelopment Hydromega), a predecessor company to an a subsidiary entity of APUC. The Québec AG at trial claimed $5.4 million for amounts that Algonquin Dévelopment Côte Ste-Catherine Inc. had been paying to Seaway Management under the water lease relating to the Côte Ste-Catherine hydroelectric generating facility. Algonquin Dévelopment (Côte Ste-Catherine) Inc. brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009, and the appeal was heard in January 2011.

On October 21, 2011, the Québec Court of Appeal ordered Algonquin Dévelopment (Côte Ste-Catherine) Inc. to pay approximately $5.4 million (including interest) to the government of Québec relating to water lease payments that Algonquin Dévelopment (Côte Ste-Catherine) Inc. has been paying to the Seaway Management under the water lease 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 $6.0 million. The parties are attempting to resolve this matter through good faith negotiations.

Long Sault global adjustment claim

In December 2012, N-R Power and Energy Corporation, Algonquin Power (Long Sault) Partnership, and N-R Power Partnership ("Long Sault") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global adjustment ("GA") as a price escalator. As a result of the OEFC's application of the new GA calculation to the calculation of total market cost of electricity ("TMC") of and, in turn, an index derived from TMC, the rate OEFC has paid to Long Sault under the PPA beginning with the application of OEFC's new TMC calculation in July 2011 has not escalated as contemplated in the PPA and term sheet. A Notice of Application was issued at the end of December 2012 with supporting materials filed at the end of April 2013. The Application was heard in May 2014. On March 12, 2015, the Ontario Superior Court of Justice ruled that the methodology that the OEFC used from January 1, 2011 onward to calculate payments under Long Sault's PPA, and those of other producers, did not comply with the terms of those PPAs. The decision further requires the OEFC to revert to its pre-2011 methodology for calculating payments and to pay producers the difference between the payments calculated by the OEFC since 2011 and the amount of the payments they would have received using the pre-2011 methodology, plus interest and costs. The OEFC has until April 13, 2015 to appeal this decision.

Dimos and Katsekas Breach of Contract Claim

On September 30, 2013, Dimos and Katsekas previous owners of the Clement Dam Hydroelectric, LLC. ("Clement Dam Hydro Facility"), filed a demand for arbitration with Algonquin Power Fund (America) Inc. ("APFA") alleging breach of the Purchase Agreement and Royalty Agreement. The claim is for $1,345,257 for alleged breach of such agreements and $155,821 for alleged unpaid royalties. The plaintiffs have demanded arbitration pursuant to such agreements. An arbitration hearing date is scheduled for May, 2015.

The Royalty Agreement obligations were guaranteed by the Clement Dam Hydro Facility pursuant to a guaranty. On December 14, 2014, Dimos and Katsekas filed a complaint against the Clement Dam Hydro Facility which seeks to enforce certain obligations under a guaranty. In the event the claimants prevail against APFA in the aforementioned arbitration, and APFA does not pay any judgment rendered against it, claimants will pursue their claims against the Clement Dam Hydro Facility. APFA is defending the Clement Dam in this matter pursuant to the sale agreement with the purchaser of the Clement Dam Hydro Facility. At present, the litigation has been stayed pending the outcome of the arbitration proceeding.

Synergics Energy Services, LLC, Breach of Contract Claim

On September 4, 2013, the plaintiff, previous owners of the Great Falls Hydro Facility, filed a complaint for alleged breach of the 2000 purchase and sale agreement and failure to pay a transfer payment thereunder in the event of the sale of the hydro facility. The claim is for $3,000,000 for alleged breach of the 2000 purchase and sale agreement. The case has been settled.

Conex Energy-Canada, LLC and Conex Energy, Inc. Breach of Contract Claim

On October 31, 2013, the plaintiffs filed a complaint for, among other things, alleged breach of a confidential agreement in relation to the development and construction of the 10-megawatt solar photovoltaic Cornwall Solar Facility. On March 3, 2014, Algonquin brought a motion to dismiss the case. The Court has since dismissed the case.

Bryson School District in Texas Property Taxes Claim

On February 10, 2014, the Generation Group received correspondence from the Bryson School District (the "School District") in Texas regarding Senate Wind LLC's property taxes claiming the Senate Wind Facility owes an additional $2.2 million of property taxes based on an indemnity in the 2010 agreement with the School District. Senate Wind LLC and the District have settled this matter.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarter ended December 31, 2014:

(all dollar amounts in $ millions except per share information)	1st Quarter 2014	2nd Quarter 2014	3rd Quarter 2014	4th Quarter 2014
Revenue	$ 343.5	$ 189.3	$ 151.9	$ 259.3
Adjusted EBITDA	97.5	66.4	41.4	84.3
Net earnings / (loss) attributable to shareholders from continuing operations	35.6	15.3	(6.1)	33.1
Net earnings / (loss) attributable to shareholders	35.9	14.6	(6.3)	31.6
Net earnings / (loss) per share from continuing operations	0.16	0.06	(0.04)	0.13
Net earnings / (loss) per share	0.17	0.06	(0.04)	0.13
Adjusted net earnings	36.8	16.5	(0.4)	35.2
Adjust net earnings per share	0.17	0.07	(0.01)	0.14
Total Assets	3,652.7	3,561.9	3,808.5	4,113.7
Long term debt[1]	1,409.4	1,389.3	1,413.5	1,280.0
Dividend declared per common share	0.09	0.09	0.10	0.10
	1st Quarter 2013	**2nd Quarter 2013**	**3rd Quarter 2013**	**4th Quarter 2013**
Revenue	$ 193.3	$ 148.8	$ 127.9	$ 205.3
Adjusted EBITDA	62.8	56.5	40.2	68.5
Net earnings / (loss) attributable to shareholders from continuing operations	20.3	15.8	6.3	19.8
Net earnings/(loss) attributable to shareholders	19.2	(18.1)	6.0	13.2
Net earnings / (loss) per share from continuing operations	0.09	0.08	0.02	0.09
Net earnings/(loss) per share	0.09	(0.09)	0.02	0.06
Adjusted net earnings	19.6	15.4	6.9	18.8
Adjust net earnings per share	0.09	0.08	0.03	0.08
Total Assets	3,476.5	3,201.8	3,156.4	3,476.5
Long term debt[1]	1,255.5	1,091.5	1,092.0	1,255.6
Dividend declared per common share	0.08	0.09	0.09	0.09

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

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

Quarterly revenues have fluctuated between $127.9 million and $343.5 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between net earnings attributable to shareholders of $35.9 million and a net loss of $18.1 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

ISSUANCE OF FOURTH QUARTER AND YEAR END FINANCIAL RESULTS

Shortly before the originally scheduled release of its 2014 financial results, APUC became aware of certain anonymous, unproven allegations regarding certain APUC personnel. APUC shared the allegations with its auditors, and delayed releasing its financial results in order to consider, together with the auditors, whether certain of the allegations which related to Algonquin's financial reporting and related practices could impact its financial results. This assessment, which was led by a committee of independent directors with the assistance of independent legal and accounting advisors was completed and on March 16, 2015 APUC released its financial results, having determined that the allegations did not impact APUC's financial results. The committee's investigation into the allegations which are not related to APUC's financial reporting and related practices is continuing to be dealt with in a confidential manner in accordance with APUC's complaint-handling policies.

DISCLOSURE CONTROLS

At the end of the fiscal year ended December 31, 2014, 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, 2014, 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, 2014, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. On May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission (COSO) published? an updated Internal Control - Integrated Framework (2013) and related illustrative documents. The company adopted the new framework in 2014.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2014 based on the criteria set forth in Internal Control – Integrated Framework (2013) 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, 2014.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

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

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, Intangibles and Goodwill

The provisions for depreciation of 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 and goodwill, 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. Changes in circumstances, market conditions and estimates of future cash flows could negatively affect the recovery 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 the Distribution Group's 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 written 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. 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 if the hedging relationship was considered no longer effective.

Pension and Post-employment Benefits

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and post-employment 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. The Company used the new mortality tables (RP-2014) and the mortality improvement scale (MP-2014) that were recently released by the Society of Actuaries in the current year assumptions. This change resulted in an increase to the pension and post-employment obligations of approximately U.S. $16.5 million.

Business Combinations

The Company has completed a number of business acquisitions in the past few years. Management's judgment is required to estimate the purchase price, to identify and to fair value all assets and liabilities acquired. The determination of the fair value of assets and liabilities acquired is based upon management's estimates and certain assumptions generally included in a present value calculation of the related cash flows. A significant change in estimate could affect APUC's results of operations.

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

MANAGEMENT'S REPORT

Financial Reporting

The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The Financial Statements have been prepared in accordance with U.S. generally accepted accounting principles. Financial statements, by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board of Directors, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board of Directors for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The 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.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2014, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2014.

March 16, 2015

Ian Robertson
Chief Executive Officer

David Bronicheski
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp., which comprise the consolidated balance sheets as at December 31, 2014 and 2013 and the consolidated statements of operations, comprehensive income, equity, and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows for the years then ended, in conformity with United States generally accepted accounting principles.

Other matter

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, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 16, 2015 expressed an unqualified opinion on Algonquin Power & Utilities Corp.'s internal control over financial reporting.

Ernst & Young LLP

Chartered Professional Accountants,

Licensed Public Accountants

Toronto, Canada

March 16, 2015

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A member firm of Ernst & Young Global Limited

INDEPENDENT AUDITORS' REPORT ON INTERNAL CONTROLS UNDER STANDARDS OF THE PUBLIC COMPANY ACCOUNTING OVERSIGHT BOARD (UNITED STATES)

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). 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 in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Algonquin Power & Utilities Corp.'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, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and 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 United States 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.

In our opinion, Algonquin Power & Utilities Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

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, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for the years then ended of Algonquin Power & Utilities Corp. and our report dated March 16, 2015 expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Professional Accountants,

Licensed Public Accountants

Toronto, Canada

March 16, 2015

A member firm of Ernst & Young Global Limited

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,273	$ 13,839
Accounts receivable, net (note 4)	188,573	160,636
Natural gas in storage (note 1(g))	31,550	25,609
Supplies and consumables inventory	11,825	7,924
Regulatory assets (note 7)	61,645	26,125
Prepaid expenses	10,431	11,341
Notes receivable (note 8)	2,966	598
Deferred income taxes (note 20)	7,210	19,652
Income taxes receivable (note 20)	568	379
Derivative instruments (note 25)	10,688	9,176
Assets held for sale (note 17)	—	23,927
	334,729	299,206
Property, plant and equipment, net (note 5)	3,278,422	2,708,704
Intangible assets, net (note 6)	54,011	54,416
Goodwill (note 6)	92,328	84,647
Regulatory assets (note 7)	187,699	164,223
Derivative instruments (note 25)	31,782	27,123
Long-term investments (note 8)	43,279	32,746
Deferred income taxes (note 20)	57,065	86,632
Other assets (note 12)	35,100	18,784
	$ 4,114,415	$ 3,476,481

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 68,540	$ 14,489
Accrued liabilities	199,374	146,338
Dividends payable (note 16)	25,395	17,535
Regulatory liabilities (note 7)	20,590	21,632
Long-term liabilities (note 9)	9,130	8,339
Pension and other post-employment benefits (note 10)	333	305
Other long-term liabilities (note 13)	9,873	7,451
Advances in aid of construction (note 1(o))	1,149	1,239
Derivative instruments (note 25)	5,183	2,492
Environmental obligations (note 23(a)(ii))	19,643	10,111
Preferred shares, Series C (note 11)	1,085	1,038
Liabilities held for sale (note 17)	—	1,471
Income taxes liability (note 20)	3,633	5,159
Deferred credits (note 13)	18,638	7,778
Deferred income taxes (note 20)	3,702	2,308
	386,268	247,685
Long-term liabilities (note 9)	1,270,893	1,247,249
Advances in aid of construction (note 1(o))	79,955	77,697
Regulatory liabilities (note 7)	102,196	101,657
Deferred income taxes (note 20)	130,758	137,153
Derivative instruments (note 25)	40,088	13,729
Deferred credits (note 13)	13,624	17,115
Pension and other post-employment benefits (note 10)	138,602	70,532
Environmental obligation (note 23(a)(ii))	52,662	59,444
Other long-term liabilities (note 13)	33,227	20,492
Preferred shares, Series C (note 11)	17,608	17,767
	1,879,613	1,762,835
Redeemable non-controlling interest (note 3(c))	12,146	—
Equity:		
Preferred shares (note 14(b))	213,805	116,546
Common shares (note 14(a))	1,633,262	1,351,264
Subscription receipts (note 14(a)(iii))	110,503	—
Additional paid-in capital	33,068	7,313
Deficit	(505,305)	(488,406)
Accumulated other comprehensive income (loss) (note 15)	34,213	(31,410)
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,519,546	955,307
Non-controlling interests	316,842	510,654
Total Equity	1,836,388	1,465,961
Commitments and contingencies (note 23)		
Subsequent events (notes 3(a), 14(c)(iv) and 20)		
	$ 4,114,415	$ 3,476,481

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)	Year ended December 31	
	2014	**2013**
Revenue		
Regulated electricity distribution	$ 206,667	$ 166,156
Regulated gas distribution	446,025	260,424
Regulated water reclamation and distribution	66,419	57,350
Non-regulated energy sales	202,300	180,191
Other revenue	22,149	11,170
	943,560	675,291
Expenses		
Operating	235,984	180,346
Regulated electricity purchased	120,506	97,376
Regulated gas purchased	261,116	148,784
Non-regulated energy purchased	39,264	25,835
Administrative expenses	34,692	23,518
Depreciation of property, plant and equipment	108,974	91,978
Amortization of intangible assets	4,626	4,200
Other amortization	447	(159)
Gain on foreign exchange	(1,112)	(567)
	804,497	571,311
Operating income from continuing operations	139,063	103,980
Interest expense	62,418	53,426
Interest, dividend income and other income	(7,758)	(7,785)
Loss (gain) on sale of assets	(436)	750
Acquisition-related costs	2,552	2,140
Write-down of long-lived assets	8,463	—
Loss (gain) on derivative financial instruments (note 25(b)(iv))	1,375	(5,200)
	66,614	43,331
Earnings from continuing operations before income taxes	72,449	60,649
Income tax expense (note 20)		
Current	3,674	2,526
Deferred	13,133	6,629
	16,807	9,155
Earnings from continuing operations	55,642	51,494
Loss from discontinued operations, net of tax (note 17)	(2,127)	(42,011)
Net earnings	53,515	9,483
Net loss attributable to non-controlling interests (note 19)	(22,186)	(10,813)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 75,701	$ 20,296
Basic net earnings per share from continuing operations (note 21)	$ 0.32	$ 0.28
Basic net loss per share from discontinued operations (note 21)	(0.01)	(0.21)
Basic net earnings per share (note 21)	0.31	0.07
Diluted net earnings per share from continuing operations (note 21)	0.32	0.28
Diluted net loss per share from discontinued operations (note 21)	(0.01)	(0.20)
Diluted net earnings per share (note 21)	$ 0.31	$ 0.07

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)	Year ended December 31	
	2014	2013
Net earnings	$ 53,515	$ 9,483
Other comprehensive income:		
Foreign currency translation adjustment, net of tax recovery of $1,049 and tax expense of $149, respectively (notes 1(v), 25(b)(iii) and 25(c))	100,548	81,597
Change in fair value of cash flow hedge, net of tax expense of $7,638 and $5,103, respectively (note 25(b)(ii))	6,434	17,308
Change in unrealized appreciation in value of available-for-sale investments	1	—
Change in pension and other post-employment benefits, net of tax recovery of $22,446 and tax expense of $10,896, respectively (note 10)	(35,669)	16,727
Other comprehensive income, net of tax	71,314	115,632
Comprehensive income	124,829	125,115
Comprehensive income attributable to the non-controlling interests	7,077	31,362
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$ 117,752	$ 93,753

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, 2014

	Algonquin Power & Utilities Corp. Shareholders							
	Common shares	Preferred shares	Subscription receipts	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2013	$1,351,264	$116,546	$ —	$ 7,313	$ (488,406)	$ (31,410)	$510,654	$1,465,961
Net earnings (loss)	—	—	—	—	75,701	—	(22,186)	53,515
Redeemable non-controlling interests not included in equity	—	—	—	—	—	—	(289)	(289)
Other comprehensive income	—	—	—	—	—	42,051	29,263	71,314
Dividends declared and distributions to non-controlling interests	—	—	—	—	(75,205)	—	(4,738)	(79,943)
Dividends and issuance of shares under dividend reinvestment plan	17,395	—	—	—	(17,395)	—	—	—
Contributions received from non-controlling interests	—	—	—	—	—	—	9,934	9,934
Issuance of subscription receipts (note 14(a)(iii))	—	—	110,503	—	—	—	—	110,503
Shares issued pursuant to public offering, net of costs (note 14(a)(i))	263,869	—	—	—	—	—	—	263,869
Issuance of common shares under employee share purchase plan	734	—	—	—	—	—	—	734
Share-based compensation	—	—	—	3,203	—	—	—	3,203
Preferred shares Series D, net of costs (note 14(b))	—	97,259	—	—	—	—	—	97,259
Acquisition of non-controlling interest (note 3(g))	—	—	—	22,552	—	23,572	(205,796)	(159,672)
Balance, December 31, 2014	$1,633,262	$213,805	$ 110,503	$ 33,068	$ (505,305)	$ 34,213	$316,842	$1,836,388

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2013

	Algonquin Power & Utilities Corp. Shareholders							
	Common shares	Preferred shares	Subscription receipts	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2012	$1,245,326	$116,546	$ 61,160	$ 5,224	$ (406,143)	$ (104,867)	$484,883	$1,402,129
Net earnings (loss)	—	—	—	—	20,296	—	(10,813)	9,483
Other comprehensive income	—	—	—	—	—	73,457	42,175	115,632
Dividends declared and distributions to non-controlling interests	—	—	—	—	(59,773)	—	(5,591)	(65,364)
Dividends and issuance of shares under dividend reinvestment plan	13,970	—	—	—	(13,970)	—	—	—
Exercise and conversion of subscription receipts	90,464	—	(90,464)	—	—	—	—	—
Issuance of subscription receipts (note 14(a)(iii))	—	—	29,304	—	—	—	—	29,304
Conversion and redemption of convertible debentures	960	—	—	—	—	—	—	960
Issuance of common shares under employee share purchase plan	544	—	—	—	(17)	—	—	527
Share-based compensation expense	—	—	—	2,089	—	—	—	2,089
Preferred shares, Series C (note 11)	—	—	—	—	(18,497)	—	—	(18,497)
Acquisition of non-controlling interest (note 18)	—	—	—	—	(10,302)	—	—	(10,302)
Balance, December 31, 2013	$1,351,264	$116,546	$ —	$ 7,313	$ (488,406)	$ (31,410)	$510,654	$1,465,961

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of Canadian dollars)	Year ended December 31 2014	2013
Cash provided by (used in):		
Operating Activities		
Net earnings from continuing operations	$ 55,642	$ 51,494
Adjustments and items not affecting cash:		
Depreciation of property, plant and equipment	108,974	91,978
Amortization of intangible assets	4,626	4,200
Other amortization	1,799	2,891
Deferred taxes	13,133	6,629
Unrealized loss (gain) on derivative financial instruments	3,046	(6,758)
Share-based compensation	3,203	2,000
Cost of equity funds used for construction purposes	(1,910)	(1,786)
Pension and post-employment expense	(2,050)	(302)
Write-down of long-lived assets	8,463	—
Loss on sale of long-lived assets	—	750
Changes in non-cash operating items (note 24)	(1,790)	(47,819)
Changes in non-cash operating items from discontinued operations (note 24)	1,262	36
Cash used in discontinued operations (note 17)	(1,682)	(4,388)
	192,716	98,925
Financing Activities		
Cash dividends on common shares	(57,848)	(52,335)
Cash dividends on preferred shares	(9,503)	(5,400)
Cash contributions from non-controlling interests	11,845	—
Production based cash contributions from non-controlling interest	8,976	1,672
Cash distributions to non-controlling interests	(4,738)	(7,263)
Issuance of common shares, net of costs	261,452	29,983
Proceeds from subscription receipts	110,503	—
Issuance of preferred shares, net of costs	96,271	—
Deferred financing costs	(3,043)	(2,240)
Increase in deferred insurance proceeds & revenue	13,132	—
Acquisition of non-controlling interest	(127,121)	—
Increase in long-term liabilities	236,528	950,346
Decrease in long-term liabilities	(286,552)	(685,472)
Increase (decrease) in advances in aid of construction	(48)	2,299
Increase (decrease) in other long-term liabilities	5,486	(1,574)
	255,340	230,016
Investing Activities		
(Increase) decrease in restricted cash	(11,034)	1,430
Increase in other assets	(2,751)	(3,004)
Distributions received in excess of equity income	264	727
Proceeds from sale of discontinued operations	20,826	24,968
Receipt of principal on notes receivable	280	109
Additions to property, plant and equipment	(432,373)	(158,377)
Acquisitions of long-term investments	(25,432)	—
Acquisitions of operating entities	(8,757)	(239,014)
Proceeds from sale of investment	5,709	3,408
	(453,268)	(369,753)
Effect of exchange rate differences on cash	646	1,529
Decrease in cash and cash equivalents	(4,566)	(39,283)
Cash and cash equivalents, beginning of year	13,839	53,122
Cash and cash equivalents, end of year	$ 9,273	$ 13,839

Supplemental disclosure of cash flow information:	2014	2013
Cash paid during the year for interest expense	$ 60,682	$ 44,185
Cash paid during the year for income taxes	$ 2,571	$ 1,107
Non-cash transactions: Property, plant and equipment acquisitions in accruals	$ 25,568	$ 10,829

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC is a diversified generation, transmission and distribution utility company. The distribution business group operates in the United States under the name of Liberty Utilities Co. ("Distribution Group") and provides rate regulated water, electricity and natural gas utility services. The non-regulated generation business group operates under the name Algonquin Power Co. ("Generation Group") and owns or has interests in a portfolio of North American based contracted wind, solar, hydroelectric and natural gas powered generating facilities. The transmission business group operates under the name Liberty Utilities (Pipeline & Transmission) ("Transmission Group") and invests in rate regulated electric transmission and natural gas pipeline systems in the United States and Canada.

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 (note 1(m)). Intercompany transactions and balances have been eliminated.

(c) Accounting for rate regulated operations

The regulated utility operating companies owned by the Company 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 ("FASB") ASC Topic 980, Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities 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 matters" 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 earnings for any remaining regulatory assets (liabilities). The impact could be material to the Company's reported financial condition and results of operations.

The electric and gas 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.

(e) Restricted cash

Restricted cash represents 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 as part of other assets (note 12) in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

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

1. Significant accounting policies (continued)

(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) Natural gas in storage

Natural gas in storage is reflected at weighted average cost or first-in-first-out as required by 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(d)).

(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.

AFUDC represents the cost of borrowed funds and a return on other funds. Under ASC 980, an allowance for funds used during construction projects that are included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. For operations that do not apply regulatory accounting, interest related only to debt is capitalized as a cost of construction in accordance with ASC 835 Interest. The interest capitalized that relates to debt reduces interest expense on the consolidated statements of operations. The AFUDC capitalized that relates to equity funds is recorded as interest, dividend and other income on the consolidated statements of operations.

	2014	2013
Interest capitalized on non-regulated property	**$ 3,584**	$ 669
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	**1,577**	1,055
Allowance for equity funds	**1,910**	1,786
Total	**$ 7,071**	$ 3,510

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred. Cost incurred for major expenditures or overhauls that occur at regular intervals over the life of an asset are capitalized and depreciated over the related interval.

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

1. Significant accounting policies (continued)

(i) Property, plant and equipment (continued)

Investment tax credits and government grants are recorded as a reduction to the cost of assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Contributions in aid of construction represent amounts contributed by customers, governments and developers to assist with the funding of some or all of 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.

The Company's depreciation is based on the estimated useful lives of the depreciable assets in each category and is determined using the straight-line method. The ranges of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2014	**2013**	**2014**	**2013**
Generation Group				
Renewable	**3 – 60**	3 – 60	**36**	35
Thermal	**3 – 40**	3 – 40	**25**	24
Distribution Group				
Gas	**5 – 100**	5 – 80	**41**	38
Electrical	**5 – 75**	8 – 75	**41**	41
Water & wastewater	**5 – 75**	5 – 50	**39**	39
Equipment	**5 – 50**	5 – 50	**14**	24

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of the Distribution Group 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 operations 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) Intangible assets

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

During the fourth quarter of each year, and when indicators of impairment are present, the Company assesses qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit to which goodwill is attributed 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 or if a quantitative assessment is elected, 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.

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 analyses to assess whether its operations and investments represent VIEs. To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements 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 right to receive benefits or 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 (note 8(a)).

The Long Sault Hydroelectric Facility ("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 70% after tax cash flows of the facility from 2014 to 2027 and 62.5% 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. Effective December 31, 2013, APUC acquired an equity interest in Long Sault (note 18). APUC has determined that the facility is a VIE. Since the Company is the primary beneficiary, 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 $42,689 (2013 - $44,319) and $36,049 (2013 - $37,143), respectively. The Long Sault debt only has recourse over the Long Sault generating assets. The financial performance of Long Sault reflected on the consolidated statements of operations includes non-regulated energy sales of $10,778 (2013 - $10,155), operating expenses and amortization of $3,201 (2013 - $2,391) and interest expense of $3,781 (2013 - $3,632).

The Saint-Damase Wind Powered Generating Facility ("Saint-Damase") is a 24 megawatt ("MW") wind powered generating facility located near St. Damase, Quebec which achieved commercial operation on December 2, 2014. The Company owns a 50% interest in the corporation with the remaining 50% interest held by the Municipality of Saint-Damase. The Company also provided subordinated construction loans to the project. APUC has determined that the corporation holding the facility is a VIE. Since the Company is the primary beneficiary, Saint- Damase is subject to consolidation by the Company. Total net book value of generating assets and third-party long-term debt of Saint-Damase amounts to $69,655 and $23,400, respectively. The financial performance of Saint-Damase reflected on the consolidated statements of operations for its first month of operations in 2014 includes non-regulated energy sales of $440, operating expenses and amortization of $217 and interest expense of $39.

(n) Long-term investments and notes receivable

Investments in which APUC has significant influence but are not controlled are accounted using the equity method. Equity method investments are initially measured at cost including transaction costs and interest when applicable. APUC records its share in the income or loss of its investees in interest, dividend and other income in the consolidated statements of operations.

1. Significant accounting policies (continued)

(n) Long-term investments and notes receivable (continued)

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable are initially recorded at cost, which is generally face value. Subsequent to acquisition, the notes receivable 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. Interest from long-term investments is recorded as earned.

If a loss in value of a long-term investment is considered other than temporary, an allowance for impairment on the investment is recorded for the amount of that loss. 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.

(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 on the consolidated balance sheet.

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 2014, $4,608 (2013 - $627) 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 Company's 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 creditworthy.

(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 OPEB plans on the consolidated balance sheets. The Company's expense and liabilities are determined by actuarial valuations, using assumptions that are evaluated annually as of 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 and modifications to prior services are recorded as actuarial gains and losses in accumulated other comprehensive income ("AOCI") 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 statements of operations.

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) Share-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 share-based compensation as a cost in the consolidated 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) Non-controlling interests

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

Certain of the Company's U.S. based wind and solar businesses are organized as limited liability corporations and partnerships and have non-controlling Class A membership equity investors ("Class A partnership units") which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the non-controlling interest holders in these subsidiaries is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting. The HLBV method uses a balance sheet approach, which measures the allocation of income or loss of the Class A partnership units 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 (note 19).

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

Equity instruments subject to redemption upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. The Company records temporary equity at issuance based on cash received less any transaction costs. At each balance sheet date, the Company reevaluates the classification of its redeemable instruments, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Increases or decreases in the carrying amount of a redeemable instrument are recorded within accumulated deficit. When the redemption feature lapses or other events cause the classification of an equity instrument as temporary equity to be no longer required, the existing carrying amount of the equity instrument is reclassified to permanent equity at the date of the event that caused the reclassification.

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 revenue and sales 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.

Revenue for the Company's Calpeco Electric System, Peach State and New England Gas Systems is subject to a revenue decoupling mechanism approved by their respective regulator which require to charge approved annual delivery revenues on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers (note 7(j)).

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 wastewater 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.

On occasion, a utility is permitted to implement new rates that have not been formally approved by the regulatory commission, which are subject to refund. The Company recognizes revenue based on the interim rate and if needed, establishes a reserve for amounts that could be refunded based on experience for the jurisdiction in which the rates were implemented.

Revenue is recorded net of sale taxes.

During the year, the Company settled insurance claims for business interruption at some of its renewable generation facilities under repairs and as a result recognized revenue of $1,227 (2013 - $6,455).

(v) Foreign currency translation

The Company’s reporting currency is the Canadian dollar.

The Company’s U.S. 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, and revenues and expenses are translated 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 OCI and are accumulated in a component of equity on the consolidated balance sheets, and are not recorded in income unless there is a complete or substantially complete sale or liquidation of the investment.

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 tax 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. Investment tax credits are recorded as an offset to the related long-lived asset and are amortized over the estimated life of the asset as credits to income tax expense.

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 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

Accounts receivable and notes receivable are measured at amortized cost and there is no liquid market for these investments. Long-term liabilities, Series C preferred shares 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 that are directly attributable to the issuance of financial liabilities, costs of arranging the Company's revolving credit facilities 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 the revolving credit facilities are amortized on a straight-line basis over the term of the respective revolving credit 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 sheets at their respective fair values. The fair value recognized on derivative instruments executed with the same counterparty under a master netting arrangement are presented on a gross basis on the consolidated balance sheets. The amounts that could net settle are not significant. The Company applies hedge accounting to financial instruments used to manage its foreign currency risk exposure and price risk exposure associated with sales of generated electricity.

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized as OCI. The ineffective portion is immediately recognized in earnings. The amount recognized in AOCI is reclassified to earnings in the same period as the hedged cash flows affect earnings under the same line item in the consolidated statements of operations 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 AOCI is transferred to the consolidated statements of operations in the same period that the hedged item affects earnings. If the forecast transaction is no longer expected to occur, then the balance in AOCI is recognized immediately in earnings.

1. Significant accounting policies (continued)

(x) Financial instruments and derivatives (continued)

Foreign currency gain or loss on derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations, that are effective as a hedge are reported in the same manner as the translation adjustment (in OCI) related to the net investment. To the extent that the hedge is ineffective, such differences are recognized in earnings.

Calpeco Electric System and Granite State Electric System 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 ongoing 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 principal 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.

(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 consolidated 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, intangible assets and goodwill; the recoverability of notes receivable and long-term investments; the recoverability of deferred tax assets; assessments of unbilled revenue; pension and OPEB obligations; timing effect of regulated assets and liabilities; contingencies related to environmental matters; the fair value of assets and liabilities acquired in a business combination; and, the fair value of financial instruments. 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.

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

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

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

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

(b) Recent accounting guidance not yet adopted

The FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis, which ends the deferral granted to investment companies from applying the VIE guidance and makes targeted amendments to the current consolidation guidance. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the VIE characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. This ASU may be applied using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the fiscal year of adoption or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2015-01, Income Statement: Extraordinary and Unusual Items (Subtopic 225-20), to simplify income statement classification by removing the concept of extraordinary items from U.S. GAAP. As a result, items that are both unusual and infrequent will no longer be separately reported net of tax after continuing operations. This ASU may be applied prospectively or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. Early adoption is permitted, but only as of the beginning of the fiscal year of adoption. The adoption of this standard is not expected to have an impact on the Company's results of operations.

2. Recently issued accounting pronouncements (continued)

(b) Recent accounting guidance not yet adopted (continued)

The FASB issued ASU No. 2014-16, Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share is More Akin to Debt or to Equity. ASU No. 2014-16 clarifies how current guidance should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. In addition, ASU No. 2014-16 clarifies that in evaluating the nature of a host contract, an entity should assess the substance of the relevant terms and features (that is, the relative strength of the debt-like or equity-like terms and features given the facts and circumstances) when considering how to weigh those terms and features. The effects of initially adopting ASU No. 2014-16 should be applied on a modified retrospective basis to existing hybrid financial instruments issued in a form of a share as of the beginning of the fiscal year for which the amendments are effective. Retrospective application is permitted to all relevant prior periods. ASU No. 2014-16 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2014-15, Presentation of Financial Statements — Going Concern. This new standard provides that in connection with preparing financial statements for each annual and interim reporting period, an entity’s management should evaluate whether there are conditions or events, that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the date that the financial statements are issued. This ASU will be effective for the annual reporting period ending after December 15, 2016, and for annual and interim periods thereafter. Early application is permitted. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2014-12, Compensation-Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period. This newly issued accounting standard is intended to resolve the diverse accounting treatment of those awards in practice. This ASU is required to be applied for fiscal years and interim periods beginning after December 15, 2015. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB and the International Accounting Standards Board have jointly issued a new revenue recognition standard codified in U.S. GAAP as ASU 2014-09, Revenue from Contracts with Customers (Topic 606). This newly issued accounting standard provides accounting guidance for all revenue arising from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers unless the contracts are in the scope of other U.S. GAAP requirements, such as the leasing literature. This ASU is required to be applied for fiscal years and interim periods beginning after December 15, 2016 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company is currently assessing the impact the adoption of this standard might have on its financial position or results of operations.

The FASB issued ASU 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This newly issued accounting standard raises the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. This ASU is required to be applied prospectively for fiscal years and interim periods beginning after December 15, 2014. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

3. Business acquisitions and development projects

(a) Acquisition of New Hampshire Gas

Subsequent to year-end , the Distribution Group completed the acquisition of New Hampshire Gas, a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System services approximately 1,200 propane gas distribution customers. Total purchase price for the New Hampshire Gas System is approximately U.S. $3,047, subject to certain closing adjustments.

(b) Agreement to acquire Park Water System

On September 19, 2014, the Company entered into an agreement to acquire the regulated water distribution utility Park Water Company ("Park Water System"). Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Total consideration for the utility purchase is expected to be approximately U.S. $327,000, which includes the assumption of approximately U.S. $77,000 of existing long-term utility debt and is subject to certain working capital and other closing adjustments. Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in the latter half of 2015.

(c) Development of Bakersfield Solar Project

During the year, the Company constructed a 20 MWac solar powered generating facility located in Kern County, California. As of December 31, 2014, the Company has incurred U.S $56,814 in the development and construction of the solar energy project which is recorded as property, plant and equipment. The facility was placed in service on December 31, 2014. Sales of power to the utility under the power purchase agreement is planned for early 2015.

On August 13, 2014, the Generation Group entered into a definitive partnership agreement with a third-party (the "Tax Investor"). It is anticipated that approximately U.S. $22,800 will be funded by the Tax Investor. With its partnership interest, the Tax Investor will receive the majority of the tax attributes associated with the project. The Tax Equity investment as of December 31, 2014 is U.S. $10,470.

Under certain conditions, the Tax Investor has the right to withdraw from the Bakersfield Solar Project and require the Company to redeem its interests for cash over a contractual payment period. As a result, the Company accounts for this interest as temporary equity and records this interest outside of permanent equity on the consolidated balance sheets as "Redeemable non-controlling interest". The Company records temporary equity at issuance based on cash received less any transaction costs. As of December 31, 2014, transaction costs of $956 have been recorded as a reduction to Redeemable non-controlling interest.

At each balance sheet date, the Company will reevaluate the classification of its redeemable instrument, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company will record the instruments at its redemption value. Increases or decreases in the carrying amount of a redeemable instrument will be recorded within accumulated deficit. Redemption is not considered probable as of December 31, 2014.

(d) Commercial operation of Saint-Damase Wind Facility

Saint-Damase is a 24 MW wind powered generating facility located near St. Damase, Quebec which achieved commercial operation on December 2, 2014. Total net book value of generating assets of Saint-Damase amounts to $69,655. Property, plant and equipment are amortized over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Saint-Damase Wind Generating Facility is 35 years.

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

3. Business acquisitions and development projects (continued)

(e) Commercial operation of Cornwall Solar Facility

On March 27, 2014, the Cornwall Solar Facility, a 10 MWac solar powered generating facility located near Cornwall, Ontario, commenced commercial operations. The Company invested $41,551 in the development and construction of the solar energy project which is recorded as property, plant and equipment, as well as additional amounts related to development rights and other intangible assets, for a total investment of $47,561. Property, plant and equipment are amortized over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Cornwall Solar Powered Facility is 33 years.

(f) Acquisition of White Hall Water System

On May 30, 2014, the Distribution Group acquired the assets of the White Hall Water System, a regulated water distribution and wastewater treatment utility located in White Hall, Arkansas. The White Hall Water System serves approximately 1,900 water distribution and 2,400 wastewater treatment customers. Total purchase price for the White Hall Water System assets, adjusted for certain working capital and other closing adjustments, is approximately U.S. $4,499.

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

On March 31, 2014, the Company acquired the 40% interest in Wind Portfolio SponsorCo, LLC ("Wind Portfolio SponsorCo") from Gamesa Corporación Tecnológica, S.A. for approximately U.S. $115,000. Wind Portfolio SponsorCo indirectly holds the interests in Sandy Ridge, Senate and Minonk Wind acquired in 2012. As a result of the transaction, the Generation Group now owns 100% of Wind Portfolio SponsorCo's Class B partnership units resulting in the elimination of the non-controlling interest in respect of the Class B partnership units of Wind Portfolio SponsorCo as follows:

Elimination of non-controlling interest in Class B partnership units	$	205,796
Non-controlling interest portion of currency translation adjustment recorded to AOCI		(21,029)
Non-controlling interest portion of unrealized gain on cash flow hedges recorded to AOCI		(2,543)
Decrease in deferred income tax asset		(32,551)
Additional paid-in capital		(22,552)
Cash	$	127,121

(h) Acquisition of New England Gas System

On December 20, 2013, the Company acquired certain regulated natural gas distribution utility assets (the “New England Gas System”) located in the State of Massachusetts. Total purchase price for the New England Gas System, net of the debt assumed, is $67,010 (U.S. $62,745), including the purchase price adjustment of U.S. $3,108 finalized in Q2 2014.

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

3. Business acquisitions and development projects (continued)

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

In 2014, the Company received additional information which was used to refine the estimates for fair value of assets acquired and liabilities assumed. The carrying value of those assets and liabilities were retrospectively adjusted to the amounts detailed in the table below. The key adjustments were an increase to the regulatory asset for pension of U.S. $4,642, a decrease of property, plant and equipment of U.S. $1,190, an increase of the environmental obligation of U.S. $4,408 and an increase of the pension obligation of U.S. $772.

Working capital	$	7,543
Restricted cash		595
Property, plant and equipment		83,365
Regulatory assets		52,601
Other assets		1,221
Long-term debt		(25,349)
Regulatory liabilities		(9,874)
Pension and OPEB		(26,184)
Environmental obligation		(14,933)
Deferred income tax liability, net		(1,158)
Other liabilities		(817)
Total net assets acquired	$	67,010

The determination of the fair value is based upon management's estimates and assumptions with respect to the fair values of the assets acquired and liabilities assumed.

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

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

The New England Gas System contributed revenue of $91,782 (2013 - $3,582) and net earnings of $10,819 (2013 - $1,153) to the Company's consolidated financial results for 2014.

(i) Acquisition of Shady Oaks Wind Facility

Effective January 1, 2013, the Company acquired the 109.5 MW Shady Oaks wind-powered generating facility ("Shady Oaks Wind Facility"). The purchase agreement provides for final purchase price adjustments based on working capital at the acquisition date, energy generated by the project and basis differences between the relevant node and hub prices which are expected to be finalized in 2015. Changes in measurement of the final purchase price adjustment subsequent to December 31, 2013, the end of the business combination measurement period, are recorded in current period operations. To that effect, a gain of U.S. $1,133 was recognized in 2014.

4. Accounts receivable

Accounts receivable as of December 31, 2014 include unbilled revenue of $52,880 (December 31, 2013 - $45,274) from the Company's regulated utilities. Accounts receivable as of December 31, 2014 are presented net of allowance for doubtful accounts of $7,229 (December 31, 2013 - $8,461).

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

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2014

	Cost	Accumulated depreciation	Net book value
Generation Group			
Renewable	$ 1,697,020	$ 217,615	$ 1,479,405
Thermal	130,227	53,131	77,096
Distribution Group			
Water & wastewater	358,520	78,290	280,230
Electricity	347,633	23,659	323,974
Gas	849,136	45,777	803,359
Land	19,347	—	19,347
Equipment and other	119,367	29,526	89,841
Construction in progress			
Generation	82,840	—	82,840
Distribution	122,330	—	122,330
	$ 3,726,420	$ 447,998	$ 3,278,422

2013

	Cost	Accumulated depreciation	Net book value
Generation Group			
Renewable	$ 1,438,229	$ 166,175	$ 1,272,054
Thermal	116,975	43,596	73,379
Distribution Group			
Water & wastewater	303,410	63,807	239,603
Electricity	277,679	16,782	260,897
Gas	682,445	15,769	666,676
Land	8,266	—	8,266
Equipment and other	78,881	29,100	49,781
Construction in progress			
Generation	54,432	—	54,432
Distribution	83,616	—	83,616
	$ 3,043,933	$ 335,229	$ 2,708,704

Renewable generation assets include cost of $155,629 (2013 - $86,774) and accumulated depreciation of $34,013 (2013 - $31,739) related to facilities under capital lease or owned by consolidated VIEs. Depreciation expense of facilities under capital lease was $2,274 (2013 - $2,155).

Investments tax credits, government grants and contributions received in aid of construction of $362 (2013 - $3,098) 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.

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

6. Intangible assets and goodwill

Intangible assets consist of the following:

2014

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 64,605	$ 33,704	$ 30,901
Customer relationships	31,094	7,984	23,110
	$ 95,699	$ 41,688	$ 54,011

2013

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 61,430	$ 28,987	$ 32,443
Customer relationships	28,512	6,539	21,973
	$ 89,942	$ 35,526	$ 54,416

Estimated amortization expense for intangible assets for the next two years is $4,750 each year, $3,000 in year three, $2,640 in year four and $2,580 in year five.

Changes in goodwill are as follows:

	Distribution Group
Balance, January 1, 2013	$ 61,459
Business acquisitions	17,260
Adjustments	748
Foreign exchange	5,180
Balance, December 31, 2013	$ 84,647
Foreign exchange	7,681
Balance, December 31, 2014	$ 92,328

7. Regulatory matters

The Company's regulated utility operating companies are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting policies, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company's regulated utility operating companies are accounted for under the principles of ASC 980. Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate-setting process.

At any given time, the Company can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the consolidated financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period.

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

7. Regulatory matters (continued)

On March 17, 2014, the Granite State Electric System received a Final Order from the New Hampshire Public Utilities Commission approving a rate increase of U.S. $10,875 consisting of U.S. $9,760 in base rates and an additional U.S. $1,115 for incremental capital expended after the test year. In addition, the Order allows for a one time recovery of rate case expenses of U.S. $390. The new rates were effective as of April 1, 2014 for service rendered on and after July 1, 2013.

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

In May 2014, the Peach State Gas System received a Final Order from the Georgia Public Service approving an annual revenue increase of U.S. $3,235 in connection with its annual GRAM filing on October 1, 2013. The new rates were effective as of June 1, 2014 for service rendered on and after February 1, 2014.

On December 4, 2014, the Peach State Gas System received a Final Order from the Georgia Public Service approving an annual revenue increase of U.S. $3,680 in connection with its annual GRAM filing on October 1, 2014. The new rates are effective as of February 1, 2015.

Regulatory assets and liabilities consist of the following:

	2014	2013
Regulatory assets		
Environmental costs (a)	**$ 102,735**	$ 85,029
Pension and post-employment benefits (b)	**65,745**	64,997
Storm costs (c)	**3,080**	5,437
Commodity costs adjustment (d)	**41,502**	15,904
Rate case costs (e)	**4,161**	3,119
Vegetation management	**3,260**	2,297
Debt premium (f)	**4,658**	4,504
Rate adjustment mechanism (j)	**6,207**	28
Asset retirement obligation (g)	**1,682**	1,468
Tax related	**4,350**	2,995
Other	**11,964**	4,570
Total regulatory assets	**$ 249,344**	$ 190,348
Less current regulatory assets	**(61,645)**	(26,125)
Non-current regulatory assets	**$ 187,699**	$ 164,223
Regulatory liabilities		
Cost of removal (h)	**$ 78,013**	$ 68,698
Rate-base offset (i)	**23,427**	25,082
Commodity costs adjustment (d)	**10,389**	17,394
Pension and post-employment benefits (b)	**592**	6,770
Rate adjustment mechanism (j)	**448**	1,681
Storm costs (c)	**1,030**	—
Depreciation adjustment mechanism	**3,518**	—
Tax related	**145**	133
Other	**5,224**	3,531
Total regulatory liabilities	**$ 122,786**	$ 123,289
Less current regulatory liabilities	**(20,590)**	(21,632)
Non-current regulatory liabilities	**$ 102,196**	$ 101,657

7. Regulatory matters (continued)

(a) Environmental remediation costs recovery: Actual expenditures incurred for the clean-up of certain former gas manufacturing facilities (note 23 (a)(ii)) are recovered through rates over a period of 7 years and in a jurisdiction are subject to an annual cap.

(b) Pension and post-employment benefits: As part of business acquisitions, the regulators authorized a regulatory asset or liability being set up for the amounts of pension and post-employment benefits that have not yet been recognized in net periodic cost and were presented as AOCI prior to the acquisition. An amount of $28,284 relates to a recent acquisition and was authorized for recognition as an asset by the regulator. Recovery is anticipated to be approved in a final rate order in 2015. The balance is recovered through rates over the future services years of the employees at the time the regulatory asset was set up (an average of 10 years) or consistent with the treatment of OCI under ASC 712 Compensation-Nonretirement Postemployment Benefits and ASC 715 Compensation-Retirement Benefits before the transfer to regulatory asset occurred.

(c) Storm costs: Incurred repair costs resulting from certain storms over or under amounts collected from customers, which are expected to be recovered or refunded through rates.

(d) Commodity costs adjustment: The revenue of the electric and natural gas utilities includes 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 statements of operations but rather is deferred and recorded as a regulatory asset or liability on the consolidated balance sheets. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of natural gas or electricity in future periods, subject to regulatory review. Derivatives are often utilized to manage the price risk associated with natural gas purchasing activities in accordance with the expectations of state regulators. The gains and losses associated with these derivatives (note 25 (b)(i)) are recoverable through the commodity costs adjustment.

(e) 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.

(f) Debt premium: The value of debt assumed in the acquisition of the New England Gas System has been recorded at fair value in accordance with ASC 805 Business Combinations. The Massachusetts regulator allows for recovery of interest at the coupon rate of the debt and a regulatory asset has been recorded for the difference between the fair value and face value of the debt. The debt premium is recovered over the remaining term of the debt (note 9).

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

(h) 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.

(i) Rate-base offset: The regulators 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.

(j) Rate adjustment mechanism: Revenue for Calpeco Electric System and Peach State Gas System is subject to a revenue decoupling mechanism approved by their respective regulator which require charging approved annual delivery revenues on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers. In addition, retroactive rate adjustments for services rendered but collected over a period not exceeding twenty-four months is accrued upon approval of the Final Order.

As recovery of regulatory assets is subject to regulatory approval, if there were any changes in regulatory positions that indicate recovery is not probable, the related cost would be charged to earnings in the period of such determination. The Company earns carrying charges on the regulatory balances related to commodity costs adjustment, rate case costs, vegetation management and storm costs in some jurisdictions.

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

8. Long-term investments

Long-term investments consist of the following:

	2014	2013
Equity-method investees		
50% interest in Odell Wind Project (a)	**$ 2,267**	$ —
2.5% interest in natural gas pipeline development (b)	**1,063**	—
32.4% of Class B non-voting shares of Kirkland Lake Power Corp. (c)	**1,512**	4,851
25% of Class B non-voting shares of Cochrane Power Corporation (c)	**—**	3,772
50% interest in the Valley Power Partnership	**1,253**	1,718
Other	**640**	325
Total	**$ 6,735**	$ 10,666
Notes receivable		
Development loans (a)	**$ 17,582**	$ —
Red Lily Senior loan, interest at 6.31% (d)	**11,588**	11,588
Red Lily Subordinated loan, interest at 12.5% (d)	**6,565**	6,565
Chapais Énergie, Société en Commandite interest at 10.789%	**649**	1,928
Silverleaf resorts loan, interest at 15.48% maturing July 2020	**2,344**	2,149
Other	**782**	448
	39,510	22,678
Less current portion	**(2,966)**	(598)
Total	**$ 36,544**	$ 22,080
Total long-term investments	**$ 43,279**	$ 32,746

(a) Odell Wind Project

On November 14, 2014, the Company acquired a 50% equity interest in Odell SponsorCo LLC ("Odell SponsorCo"), which indirectly owns a 200 MW construction-stage wind development project ("Odell Wind Project") in the state of Minnesota. The total construction costs of the Odell Wind Project are estimated to be U.S. $322,766.

On the acquisition of the Odell Wind Project by Odell SponsorCo, the two members each contributed U.S. $1,000 to the capital of Odell SponsorCo. Upon execution of third-party construction loan and tax equity documents expected in the second quarter of 2015, each party will contribute another U.S. $23,800 to the capital of Odell SponsorCo. The Company holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments, on commencement of operations, which is expected in late 2015 or early 2016.

As of December 31, 2014, Odell SponsorCo is considered a VIE namely due to the low level of its equity at that point. The Company is not considered the primary beneficiary of Odell SponsorCo as the two members have joint control and all decisions must be unanimous. As such, the Company is accounting for the joint venture as an equity method investment. The Company's maximum exposure to loss is $311,966 as of December 31, 2014.

8. Long-term investments (continued)

(a) Odell Wind Project (continued)

The Company entered into a committed loan and credit support facility with Odell SponsorCo. During construction, the Company is obligated to provide Odell SponsorCo with cash advances and credit support (in the form of letters of credit, escrowed cash, or guarantees) in amounts necessary for the continued development and construction of the Odell Wind Project. The loan bears interest at an annual rate of 8% on outstanding principal amount until commercial operation date and 5% thereafter until maturity date, and the letters of credit are charged an annual fee of 2% on their stated amount. Any loan outstanding to Odell SponsorCo, to the extent not otherwise repaid earlier, is repayable in cash on the fifth anniversary of the availability termination date which is thirty days following the commercial operation date.

As of December 31, 2014, the Company had loaned U.S. $13,159 to Odell SponsorCo for development costs of the Odell Wind Project. No interest revenue was accrued on the loan due to insufficient collateral in Odell SponsorCo. The following credit support was also issued by the Company: a U.S. $15,000 letter of credit on behalf of the Odell Wind Project, to the utility under the PPA; guarantee of the obligations of the Odell Wind Project under the wind turbine supply agreement between Odell SponsorCo and Vestas-American Wind Technology, Inc.; a U.S.$23,800 letter of credit on behalf of Odell SponsorCo, to Enel Kansas, LLC under the purchase and sale agreement. The guarantee obligations are recognized under other long-term liabilities and were valued at U.S. $720 using a probability weighted discounted cash flow (level 3).

(b) Natural Gas Pipeline Development

On November 24, 2014, APUC announced that it plans to participate in the development of Kinder Morgan Inc's proposed Northeast Energy Direct natural gas pipeline project. The Company and Kinder Morgan Operating L.P. "A" formed a new entity ("Northeast Expansion LLC") to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas transmission pipeline to be constructed between Wright, NY and Dracut, MA. The pipeline capacity will be contracted with local distribution utilities, and other customers in the northeast U.S. The project is expected to reach commercial operations by late 2018. Under the agreement, APUC initially subscribed for a 2.5% interest in Northeast Expansion LLC with an opportunity to increase its participation up to 10%. The total capital investment assuming APUC exercises its right to subscribe for 10% of the pipeline is expected be up to U.S. $400,000, depending on the final pipeline configuration and design capacity by the end of 2018. As of December 31, 2014, APUC had invested U.S. $375 in Northeast Expansion LLC. The Company assessed that its interest of 2.5% in a limited liability corporation together with the option to increase its participation to 10% and the commitment from its New Hampshire subsidiary to a firm gas transportation agreement for service on the pipeline facilities provide significant influence. As such, the interest is accounted as an equity method investment.

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

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

8. Long-term investments (continued)

(d) Red Lily I

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

The senior debt facility consists of two tranches. A third-party lender advanced $27,000 of senior debt to the Partnership as Tranche 1. In 2011, APUC advanced $13,000 of senior debt as Tranche 2 to the Partnership and received a pre-payment of $1,412 in 2012. Another third-party lender has also advanced $4,000 of senior debt Tranche 2 to the Partnership. The Company's senior loan Tranche 2 to the Partnership earns interest at the rate of 6.31% and will mature in 2016. Tranche 1 is being repaid in equal blended monthly payments of principal and interest at a rate of 6.99% based upon a twenty-five year amortization. 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%, and 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 the Company'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 of December 31, 2014 and 2013 was determined to be negligible.

The above notes are secured by the underlying assets of the respective facilities.

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

9. Long-term liabilities

Long-term liabilities consist of the following:

	2014	2013
Generation Group		
$350,000 revolving credit facility, interest rate is equal to bankers' acceptance or LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is BA or LIBOR plus 1.45%, maturing July 31, 2018.	**$ 23,400**	$ 124,570
Algonquin Power Co.: Senior Unsecured Notes: $200,000 bearing an interest rate of 4.65% maturing February 15, 2022; $150,000 bearing an interest rate of 4.82% maturing February 15, 2021; $135,000 bearing an interest rate of 5.50% maturing July 25, 2018. The notes have interest only payments, payable semi-annually in arrears.	**484,553**	284,757
Shady Oaks Wind Facility: Senior Debt: U.S. $76,000 Chinese Development Bank Corporation loan facility, bearing an interest rate of 6 month LIBOR plus 280 basis points, maturing June 30, 2026. The facility has principal and interest payments, payable semi-annually in arrears.	**88,168**	129,759
Long Sault Hydro Facility: Senior Debt: Bonds bearing an interest rate of 10.21% maturing December 31,2027. The bonds have interest and principal payments, payable monthly in arrears.	**36,048**	37,143
Sanger Thermal Facility: Senior Debt: U.S. $19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bond Series 1990A, bearing an effective interest rate determined by the remarketing agent. The bond has interest only payments, payable monthly in arrears. The effective interest rate in 2014 was 2.01% (2013 – 1.72%). The bonds were fully repaid on December 31, 2014.	**—**	20,421
Chuteford Hydro Facility: Senior Debt: Bonds bearing an interest rate of 11.6%, maturing April 1, 2020. The bond has principal and interest payments, payable monthly in arrears.	**3,028**	3,417
Distribution Group		
U.S. $200,000 revolving credit facility, interest rate is equal to LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 1.25%, maturing September 30, 2018.	**23,898**	85,620
Liberty Utilities Co.: Senior Unsecured Notes: U.S. $ 50,000, bearing an interest rate of 3.51%, maturing July 31, 2017; U.S. $ 25,000, bearing an interest rate of 3.23%, maturing July 31, 2020; U.S. $115,000, bearing an interest rate of 4.49%, maturing August 1, 2022; U.S. $ 15,000, bearing an interest rate of 4.14%, maturing March 13, 2023; U.S. $ 75,000, bearing an interest rate of 3.86%, maturing July 31, 2023; U.S. $ 60,000, bearing an interest rate of 4.89%, maturing July 30, 2027; U.S. $ 25,000, bearing an interest rate of 4.26%, maturing July 31, 2028. The notes have interest only payments, payable semi-annually.	**423,436**	388,214

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

	2014	2013
Calpeco Electric System: Senior Unsecured Notes: U.S. $45,000 bearing an interest rate of 5.19%, maturing December 29, 2020; U.S. $25,000 bearing an interest rate of 5.59%, maturing December 29, 2025. The notes have interest only payments, payable semi-annually in arrears.	**81,207**	74,452
Liberty Water Co: Senior Unsecured Notes: U.S. $50,000 bearing an interest rate of 5.60% $5,000 matures annually beginning June 20, 2016; $25,000 maturing December 22, 2020. The note bears interest payments semi-annually in arrears.	**58,005**	53,180
New England Gas System: First mortgage bonds: U.S. $6,500, bearing an interest rate of 9.44%, maturing February 15, 2020; U.S. $7,000, bearing an interest rate of 7.99%, maturing September 15, 2026; U.S. $6,000, bearing an interest rate of 7.24%, maturing December 15, 2027. The notes have interest only payments, payable semi-annually in arrears.	**27,288**	25,244
Granite State Electric System: 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 have interest only payments, payable semi-annually.	**17,402**	15,954
LPSCo Water System: 1999 and 2001 IDA Bonds bearing interest rates of 5.95% and 6.75% and maturing October 1, 2023 and October 1, 2031, respectively. The bonds have principal and interest payments, payable monthly in arrears.	**12,441**	11,668
Bella Vista Water System: Water Infrastructure Financing Authority of Arizona loans bearing interest rates of 6.26% and 6.10%, and maturing March 1, 2020 and December 1, 2017, respectively. The loans have principal and interest payments, payable monthly and quarterly in arrears.	**1,149**	1,189
	$ 1,280,023	$ 1,255,588
Less: current portion	**(9,130)**	(8,339)
	$ 1,270,893	$ 1,247,249

9. Long-term liabilities (continued)

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 the Company. The loans have certain financial covenants, which must be maintained on a quarterly basis. Noncompliance with the covenants could restrict cash distributions/dividends to the Company from the specific facilities.

Generation Group

On December 31, 2014, the U.S. $19,200 senior debt for the Sanger thermal facility was repaid.

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

On January 17, 2014, the Company issued $200,000 senior unsecured debentures bearing interest at 4.65% and with a maturity date of February 15, 2022. The debentures were sold at a price of $99.864 per $100.00 principal amount. Interest payments are payable on February 15 and August 15 each year, commencing on February 15, 2014. the Company incurred deferred financing costs of $1,568, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Concurrent with the offering, the Company entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed for fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Company'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 U.S. dollar accruals that are designated as, and are effective as, an economic hedge of the net investment in a foreign operation is reported in the same manner as the translation adjustment (in OCI) related to the net investment (note 25(b)(iii)).

Effective January 1, 2013, concurrent with the acquisition of Shady Oaks Wind Facility (note 3(i)), the Company assumed existing long-term debt of approximately U.S. $150,000. Principal of U.S. $46,000 was repaid in 2014 leaving a balance of U.S. $76,000 outstanding as of December 31, 2014. The semi-annual principal repayment schedule for the following 11.5 years ranges from U.S. $3,000 to U.S. $6,000 with a final repayment in 2026. This debt may be repaid in whole or in part on an interest payment date, annually May 15 or November 15, without penalty.

Distribution Group

On December 20, 2013, in connection with the acquisition of the New England Gas System, the Company assumed first mortgage bonds of U.S. $6,000, bearing an interest rate of 7.24%, maturing December 15, 2027; U.S. $7,000, bearing an interest rate of 7.99%, maturing September 15, 2026; and, U.S. $6,500, bearing an interest rate of 9.44%, maturing February 15, 2020.

On September 30, 2013, the Company increased the maximum availability under its senior unsecured revolving credit facility from U.S. $100,000 to $200,000 to meet future working capital requirements and allow for greater financial flexibility. The revolving credit facility has a maturity date of September 30, 2018.

On July 31, 2013, the Company issued U.S. $125,000 of senior unsecured notes through a private placement in three tranches: U.S. $25,000, bearing an interest rate of 3.23%, maturing July 31, 2020; U.S. $75,000, bearing an interest rate of 3.86%, maturing July 31, 2023; and, U.S. $25,000, bearing an interest rate of 4.26%, maturing July 31, 2028. The proceeds from the private placement financing were used to fund a portion of the acquisition of the Peach State Gas System.

On March 14, 2013, the Company issued U.S. $15,000 of senior unsecured notes through a private placement in connection with the acquisition of the Pine Bluff Water System. The notes bear interest at 4.14% and mature March 13, 2023.

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

9. Long-term liabilities (continued)

APUC

On November 19, 2013, APUC increased the maximum availability under its senior unsecured revolving credit facility from U.S. $30,000 to $65,000. The revolving credit facility will be used for general corporate purposes and has a maturity date of November 19, 2016. As of December 31, 2014 and 2013, no amounts were outstanding under this revolving credit facility.

As of December 31, 2014, the Company had accrued $18,770 in interest expense (2013 - $14,057). Interest paid on the long-term liabilities in 2014 was $61,287 (2013 - $49,746).

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

	2015	2016	2017	2018	2019	Thereafter	Total
Generation Group	$ 8,599	$ 8,779	$ 11,300	$ 169,822	$ 12,132	$ 424,517	$ 635,149
Distribution Group	531	6,393	64,435	30,349	6,492	536,626	644,826
Total	$ 9,130	$ 15,172	$ 75,735	$ 200,171	$ 18,624	$ 961,143	$1,279,975

10. Pension and other post-employment benefits

The Company provides defined contribution pension plans to its employees. The Company's contributions for 2014 were $3,287 (2013 - $2,437).

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and OPEB plans for qualifying employees in the related acquired businesses. The legacy plans of the electricity and gas utilities are non-contributory defined pension plans covering substantially all employees. Benefits are based on each employee's years of service and compensation. The Company initiated a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. 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.

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

10. Pension and other post-employment benefits (continued)

(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 as of December 31:

	Pension benefits		OPEB	
	2014	2013	**2014**	2013
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**$ 178,113**	$ 104,291	**$ 45,399**	$ 31,674
Projected benefit obligation assumed from business combination	**1,022**	73,601	**—**	17,943
Modifications to pension plan	**(560)**	81	**—**	—
Service cost	**4,828**	3,273	**2,022**	1,602
Interest cost	**8,549**	4,350	**2,186**	1,508
Actuarial loss (gain)	**39,704**	(11,395)	**14,893**	(8,499)
Benefits paid	**(8,125)**	(3,597)	**(1,255)**	(1,158)
Loss on foreign exchange	**18,432**	7,509	**5,012**	2,329
Projected benefit obligation, end of year	**$ 241,963**	$ 178,113	**$ 68,257**	$ 45,399
Change in plan asset				
Fair value of plan assets, beginning of year	**139,280**	66,524	**13,395**	10,195
Plan assets acquired in business combination	**—**	57,285	**—**	658
Actual return on plan assets	**6,568**	10,733	**1,176**	1,730
Employer contributions	**5,676**	3,013	**(222)**	1,208
Benefits paid	**(7,414)**	(3,597)	**(1,255)**	(1,157)
Gain on foreign exchange	**12,880**	5,322	**1,201**	761
Fair value of plan assets, end of year	**$ 156,990**	$ 139,280	**$ 14,295**	$ 13,395
Unfunded status	**$ (84,973)**	$ (38,833)	**$ (53,962)**	$ (32,004)
Amounts recognized in the consolidated balance sheets consists of:				
Current liabilities	**—**	(305)	**(333)**	—
Non-current liabilities	**(84,973)**	(38,528)	**(53,629)**	(32,004)
Net amount recognized	**$ (84,973)**	$ (38,833)	**$ (53,962)**	$ (32,004)

The accumulated benefit obligation for the pension plans was $219,007 and $162,179 as of December 31, 2014 and 2013, respectively.

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

10. Pension and other post-employment benefits (continued)

(a) Net pension and OPEB obligation (continued)

The amounts recognized in AOCI before tax were as follows:

	AOCI	
	Pension	OPEB
Balance, January 1, 2013	$ 3,333	$ 821
Current year net actuarial gain	(17,777)	(9,878)
Current year prior service loss	82	—
Amortization of net actuarial loss	(23)	(26)
Balance at December 31, 2013	$ (14,385)	$ (9,083)
Current year net actuarial loss	43,350	14,338
Current year prior service credit	(563)	—
Amortization of net actuarial gain	349	641
Balance at December 31, 2014	$ 28,751	$ 5,896

The net actuarial loss for the defined benefit pension plans and OPEB that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $1,074 and $356, respectively.

(b) Assumptions

Weighted average assumptions used to determine net benefit cost for 2014 and 2013 were as follows:

	Pension benefits		OPEB	
	2014	2013	2014	2013
Discount rate	**4.55%**	3.68%	**4.60%**	3.69%
Expected return on assets	**7.00%**	5.51%	**5.53%**	5.18%
Rate of compensation increase	**2.97%**	3.13%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**7.63%**	7.68%
Age 65 and after			**7.63%**	7.68%
Assumed Ultimate Medical Inflation Rate			**5.00%**	4.80%
Year in which Ultimate Rate is reached			**2019**	2019

Weighted average assumptions used to determine net benefit obligation for 2014 and 2013 were as follows:

	Pension benefits		OPEB	
	2014	2013	2014	2013
Discount rate	**3.71%**	4.55%	**3.80%**	4.60%
Rate of compensation increase	**3.01%**	2.97%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**7.00%**	7.63%
Age 65 and after			**7.00%**	7.63%
Assumed Ultimate Medical Inflation Rate			**5.00%**	5.00%
Year in which Ultimate Rate is reached			**2019**	2019

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

10. Pension and other post-employment benefits (continued)

(b) Assumptions (continued)

The Company used the new mortality tables (RP-2014) and the mortality improvement scale (MP-2014) that were recently released by the Society of Actuaries in the current year assumptions. This change resulted in an increase to the pension and OPEB obligations of approximately U.S. $16,500.

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. The rate of return assumptions are based on projected long-term market returns for the various asset classes in which the plans are invested, weighted by the target asset allocations.

The effect of a one percent change in the assumed health care cost trend rate ("HCCTR") for 2014 is as follows:

		2014
Effect of a 1 percentage point increase in the HCCTR on:		
Year-end benefit obligation	$	10,998
Total service and interest cost		623
Effect of a 1 percentage point decrease in the HCCTR on:		
Year-end benefit obligation	$	(8,664)
Total service and interest cost		(503)

(c) Benefit costs

The following table lists the components of net benefit costs for the pension plans and OPEB recorded as part of operating expenses in the consolidated statements of operations. The employee benefit costs related to businesses acquired are recorded in the consolidated statements of operations from the date of acquisition.

	Pension benefits				OPEB			
		2014		2013		**2014**		2013
Service cost	**$**	**4,828**	$	3,273	**$**	**2,022**	$	1,602
Interest cost		**8,549**		4,350		**2,186**		1,508
Expected return on plan assets		**(10,018)**		(4,160)		**(628)**		(602)
Amortization of net actuarial loss (gain)		**(346)**		23		**(641)**		26
Net benefit cost	**$**	**3,013**	$	3,486	**$**	**2,939**	$	2,534

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

10. Pension and other post-employment benefits (continued)

(d) Plan assets

The Company's investment strategy for its pension and post-employment 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 Company's target asset allocation is as follows:

Asset Class	Target (%)	Range (%)
Equity securities	74%	49.7%-78%
Debt securities	26%	21.9%-50.3%
Other	—%	0%-0.5%

The fair values of investments as of December 31, 2014, by asset category, are as follows:

Asset Class	Level 1	Percentage
Equity securities	122,943	72%
Debt securities	47,771	28%
Other	570	—%

As of December 31, 2014, the funds do not hold any material investments in APUC.

(e) Cash flows

The Company expects to contribute $4,289 to its pension plans and $2,021 to its post-employment benefit plans in 2015.

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

	2015	2016	2017	2018	2019	2020-2024
Pension plan	$ 9,933	$ 10,471	$ 11,099	$ 11,709	$ 12,234	$ 69,107
OPEB	2,157	2,416	2,697	2,908	3,060	19,472

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

11. Mandatorily redeemable Series C preferred shares

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 the Company and the legal owner of the St. Leon Wind Facility (note 18). Thirty-six of the Series C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 for $53,400 per share (fifty-three thousand and four hundred dollars per share) and have a contractual cumulative cash dividend paid quarterly until the date of redemption based on a prescribed payment schedule detailed below. As these shares are mandatorily redeemable for cash, they are accounted for as liabilities in the consolidated financial statements. The cumulative dividends are indexed in proportion to the increase in CPI over the term of the shares. The dividend is intended to approximate the distributions that otherwise would have accrued to holders of Class B limited partnership units. The Series C preferred shares are convertible into common shares at the option of the holder and the Company, at any time after May 20, 2031 and before June 19, 2031, at a conversion price of $53,400 per share.

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

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

2015	$	1,077
2016		946
2017		895
2018		1,125
2019		1,334
Thereafter to 2031		19,525
Redemption amount		5,340
		30,242
Less amounts representing interest		(11,549)
		18,693
Less current portion		(1,085)
	$	17,608

12. Other assets

Other assets consist of the following:

		2014		2013
Restricted cash	**$**	**18,702**	$	6,021
Deferred financing costs		**10,732**		9,011
Other		**5,666**		3,752
	$	**35,100**	$	18,784

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

13. Other long-term liabilities and Deferred credits

Other long-term liabilities consist of the following:

	2014	2013
Asset retirement obligation	$ **13,884**	$ 9,508
Customer deposits	**11,713**	8,774
Provision for injury and damages	**1,173**	1,215
Deferred water rights inducement	**2,683**	2,764
Contingent consideration	**1,202**	1,102
Other	**12,445**	4,580
	43,100	27,943
Less current portion	**(9,873)**	(7,451)
	$ **33,227**	$ 20,492

The asset retirement obligation mainly relates 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 sections of gas main are 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. During the year, APUC recorded additional asset retirement obligation of $2,570 (2013 - $1,651) for newly constructed renewable generation facilities.

Deferred credits consist of the following:

	2014	2013
Deferred tax credit (note 20)	$ **19,130**	$ 24,893
Deferred insurance proceeds	**12,190**	—
Deferred revenue	**942**	—
	$ **32,262**	$ 24,893
Less: current portion	**(18,638)**	(7,778)
	$ **13,624**	$ 17,115

Insurance proceeds received for some renewable generation facilities under repairs are deferred until they are virtually certain of being realized.

14. Shareholders' capital

(a) Common shares

Number of common shares:

	2014	2013
Common shares, beginning of year	**206,348,985**	188,763,486
Public offering (i)	**29,444,000**	—
Conversion and redemption of convertible debentures (ii)	**—**	150,816
Conversion of subscription receipts (iii)	**—**	15,223,016
Issuance of shares under the dividend reinvestment (iv) and employee share purchase plans ((c)(ii))	**2,356,483**	2,211,667
Common shares, end of year	**238,149,468**	206,348,985

14. Shareholders' capital (continued)

(a) Common shares (continued)

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.

On April 23, 2013, the Company's shareholders renewed its shareholders' rights plan (the "Rights Plan"). The Rights Plan has a 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.

(i) Public offering

In December 2014, APUC issued 10,055,000 common shares at $9.95 per share pursuant to a public offering for proceeds of $100,047, before issuance costs of $4,243 or $3,021 net of taxes.

In September 2014, APUC issued 19,389,000 common shares at $8.90 per share pursuant to a public offering for proceeds of $172,562, before issuance costs of $7,648 or $5,719 net of taxes.

(ii) Conversion and redemption of convertible debentures

In 2013, $960 of Series 3 Debentures were redeemed for 150,816 common shares of APUC.

(iii) Subscription receipts

On December 29, 2014, the Company received total proceeds of $77,503 from the issuance to Emera of 8,708,170 subscription receipts at a price of $8.90 per share in connection with the Odell SponsorCo acquisition (note 8(a)). At any time after the earlier of commencement of operations of the Odell Wind Project or November 14, 2015, Emera may elect to convert the subscription receipts for no additional consideration on a one-for-one basis into common shares. In the event that Emera has not elected to convert the subscription receipts by November 14, 2016, they will automatically convert into common shares.

On December 29, 2014, the Company received total proceeds of $33,000 from the issuance to Emera of 3,316,583 subscription receipts at a price of $9.95 per share in connection with the Park Water System acquisition (note 3(b)). At any time after the earlier of the Park Water System acquisition or December 29, 2015, Emera may elect to convert the subscription receipts for no additional consideration on a one-for-one basis into common shares. In the event that Emera has not elected to convert the subscription receipts by December 29, 2016, they will automatically convert into common shares.

On March 26, 2013, in connection with the acquisition of the Peach State Gas system, the Company issued 3,960,000 common shares at a price of $7.40 per share for total proceeds of $29,304 pursuant to a subscription receipt agreement with Emera.

On February 14, 2013, 11,263,016 subscription receipts issued in 2012 were exercised by Emera and the Company issued 11,263,016 common shares in exchange.

14. Shareholders' capital (continued)

(a) Common shares (continued)

(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 are purchased in the open market or are 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 706,680 common shares under the dividend reinvestment plan.

(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. On November 9, 2012, APUC issued 4,800,000 Series A preferred shares, at a price of $25 per share, for aggregate proceeds of $120,000 before issuance cost of $4,700 or $3,454 net of tax.

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. 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.

On 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 are recorded as a liability on the consolidated balance sheets (note 11).

On March 5, 2014, APUC issued 4,000,000 Series D preferred shares, at a price of $25 per share, for aggregate proceeds of $100,000 before issuance costs of $3,729 or $2,741 net of tax.

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

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

14. Shareholders' capital (continued)

(c) Share-based compensation

For the year ended December 31, 2014, APUC recorded $3,248 (2013 - $2,046) in total share-based compensation expense detailed as follows:

	2014	2013
Stock options	**$ 1,931**	$ 1,687
Directors deferred share units	**273**	155
Employee share purchase	**116**	75
Performance share units	**928**	129
Total share-based compensation	**$ 3,248**	$ 2,046

The compensation expense is recorded as part of administrative expenses in the consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As of December 31, 2014, total unrecognized compensation costs related to non-vested options and performance share unit were $2,084 and $2,380, respectively, and are expected to be recognized over a period of 1.71 years and 1.61, 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 historical 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.

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

	2014	2013
Risk-free interest rate	**1.97%**	1.61%
Expected volatility	**38%**	37%
Expected dividend yield	**3.84%**	3.83%
Expected life	**8 years**	8 years
Weighted average grant date fair value per option	**$ 2.00**	$ 2.00

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

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Stock option plan (continued)

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, 2013	3,750,727	$	5.25	6.07	$	5,939
Granted	816,402		7.72	8.00		—
Balance at December 31, 2013	4,567,129	$	5.70	5.45	$	7,814
Granted	969,998		7.95	8.00		—
Balance at December 31, 2014	5,537,127	$	6.09	4.96	$	19,648
Exercisable at December 31, 2014	3,601,647	$	5.33	4.20	$	15,531

(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. Common 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 common 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 common shares reserved for issuance from treasury by APUC under the ESPP shall not exceed 2,000,000 common 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, 2014, a total of 93,598 common shares (2013 - 85,410) were issued to employees under the ESPP.

(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 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 shares. 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. As of December 31, 2014, 110,241 (2013 - 74,786) DSUs were outstanding pursuant to the election of the directors to defer a percentage of their director's fee in the form of DSUs.

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

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(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. 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 common 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 dividends 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. During the second quarter, the Company settled 22,665 vested performance share units ("PSUs") for $162 in cash. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 common shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Company expects to settle the remaining PSUs in common shares. As a result, the PSUs continue to be accounted for as equity awards.

Compensation expense associated with PSUs is recognized rateably over the performance period and assumes that performance goals will be achieved at 100%. If goals met differ, compensation cost recognized is adjusted to reflect the performance conditions achieved.

A summary of the PSUs follows:

	Number of awards	Weighted Average Grant-Date Fair Value	Weighted Average Remaining Contractual Term (years)	Aggregate intrinsic value
Balance at January 1, 2013	83,483	$ 6.58	1.80	$ 571
Granted	5,537	6.79	1.23	41
Exercised	(20,640)	6.70	—	(151)
Forfeited	(2,185)	6.70	—	(16)
Balance at December 31, 2013	66,195	$ 6.57	0.62	$ 486
Granted, including dividends	407,962	8.22	3.00	3,333
Exercised	(22,665)	6.13	—	(185)
Forfeited	(11,406)	8.22	—	(93)
Balance at December 31, 2014	440,086	$ 6.57	1.81	$ 439
Exercisable at December 31, 2014	42,097	$ 6.86	—	$ 486

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

15. Accumulated other comprehensive income (loss)

Accumulated other comprehensive income (loss) consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain (loss) on cash flow hedges	Net change on available-for-sale investments	Pension and post-employment actuarial changes	Total
Balance, January 1, 2013	$(105,957)	$ 3,596	$ —	$ (2,506)	$ (104,867)
OCI before reclassifications	48,486	10,357	—	16,698	75,541
Amounts reclassified	—	(2,113)	—	29	(2,084)
Net current period OCI	48,486	8,244	—	16,727	73,457
Balance, December 31, 2013	$ (57,471)	$ 11,840	$ —	$ 14,221	$ (31,410)
OCI (loss) before reclassifications	65,303	6,993	519	(35,396)	37,419
Amounts reclassified	—	5,423	(518)	(273)	4,632
Net current period OCI (loss)	$ 65,303	$ 12,416	$ 1	$ (35,669)	$ 42,051
Acquisition of non-controlling interest	21,029	2,543	—	—	23,572
Balance, December 31, 2014	$ 28,861	$ 26,799	$ 1	$ (21,448)	$ 34,213

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

16. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. For the year ended December 31, 2014, the Company declared dividends to shareholders on common shares totaling $82,898 (2013 - $68,291) or $0.3695 per common share (2013 - $0.3325 per common share). The Board declared a dividend on the Company's common shares of U.S. $0.0875 per share payable on January 15, 2015 to the shareholders of record on December 31, 2014.

For the year ended December 31, 2014, the Company declared and paid dividends to Series A preferred shareholders totaling $5,400 (2013 - $5,400) or $1.125 per Series A preferred share (2013 - $1.1250 per Series A preferred share).

For the year ended December 31, 2014, the Company declared and paid dividends to Series D preferred shareholders totaling $4,103 (2013 - $nil) or $1.0257 per Series D preferred share (2013 - $nil per Series D preferred share).

17. Divestitures

(a) EFW Thermal Facility

During 2013, the Company initiated a strategic review of the Company's business plan and opportunities available for its Energy From Waste Thermal Facility ("EFW Thermal Facility") and Brampton Cogeneration Inc. ("BCI Thermal Facility"). As a result of the review, the Company decided to sell the facilities. In 2013, the net assets of the EFW and BCI were written down to their estimated fair value less cost of sale, which resulted in a write-down of the net assets of $56,851 before tax, or $42,538 net of tax of $14,313. The Company sold the EFW and BCI Thermal Facilities on April 4, 2014. These assets were part of the Generation: Thermal reporting segment.

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

17. Divestitures (continued)

(b) Sale of U.S. Hydro facilities

On June 29, 2013, the Company sold 9 small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of the Company, for gross proceeds of U.S. $23,400 for a gain on sale of U.S. $960, net of tax recovery of U.S. $1,605. On June 16, 2014, the Company sold its final small U.S. hydroelectric generating facility for U.S. $3,600. These assets were part of the Generation: Renewable reporting segment.

(c) Results from discontinued operations

The assets of the EFW, BCI Thermal Facilities and the small U.S. hydroelectric generating facilities were presented as assets held for sale on the 2013 consolidated balance sheet and the operating results from these facilities are disclosed as discontinued operations in the 2014 and 2013 consolidated financial statements.

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

	2014	2013
Non-regulated energy sales	**$ 2,174**	$ 9,327
Waste disposal fees	**2,233**	8,160
Other and interest income	**63**	336
Operating and administrative expenses	**(5,284)**	(19,720)
Foreign exchange	**111**	80
Depreciation of property, plant and equipment	**—**	(2,483)
Interest expense	**(19)**	(58)
Gain (loss) on sale of assets	**(960)**	1,016
Write-off of assets	**(1,971)**	(57,160)
Non-cash gain on sale of assets	**105**	—
Deposit on sale	**143**	—
Loss from discontinued operations, before income taxes	**(3,405)**	(60,502)
Income tax recovery	**1,278**	18,491
Loss from discontinued operations, net of income taxes	**$ (2,127)**	$(42,011)
Add:		
Depreciation of property, plant and equipment	**—**	2,483
Deposit on sale	**(143)**	—
Write-off of assets	**1,971**	57,160
Non-cash gain on sale of assets	**(105)**	—
Incurred closing costs on disposal of assets	**—**	(2,916)
Contingent liability	**—**	(613)
Income tax recovery	**(1,278)**	(18,491)
Cash used in discontinued operations	**$ (1,682)**	$ (4,388)

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

17. Divestitures (continued)

(c) Results from discontinued operations (continued)

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

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

Liabilities held for sale as of December 31, were as follows:

	2014	2013
Accounts payable and accrued liabilities	$ —	$ 1,471

18. Related party transactions

Ian Robertson and Chris Jarratt ("Senior Executives"), respectively Chief Executive Officer and Vice-Chair of APUC, are indirect shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of the Company and several related affiliates (collectively, the "Parties"). Prior to 2010, there were several related party transactions and co-owned assets which existed pursuant to the external management structure before the internalization of management which occurred on December 21, 2009.

In 2011, the Board formed an independent committee ("Independent Board Committee") and initiated a process to review all of the remaining business associations with the Parties in order to reduce and/or eliminate these relationships. The Independent Board Committee engaged independent consultants and advisors to assist with this process and to provide advice in respect thereof. Specifically, the independent advisors provided advice to the Independent Board Committee in relation to the valuations of the generating assets, tax and legal matters.

The process initiated in 2011 was completed in November 2013 and all related party transactions except as noted below, between APUC and the Parties have been addressed to the satisfaction of the Independent Board Committee and the Board as discussed below.

The following describes the business associations and resolution with APMI and Senior Executives:

Due to and from related parties

Effective December 31, 2013, APUC paid the Parties $1,829 in connection with outstanding fees and the Parties paid APUC $812 in connection with reimbursement of expenses. As at December 31, 2014, $47 (2013 - $47) remains due from Algonquin Power Systems Ltd., a corporation partially owned by the Senior Executives.

Equity interests in Rattle Brook, Long Sault, BCI

The Parties owned interests in three power generation facilities in which APUC also has an interest in. A brief description of the facilities is provided as follows:

- Rattle Brook is a 4 MW hydroelectric generating facility ("Rattle Brook") constructed in 1998 in which APUC owned a 45% interest and Senior Executives hold an equity interest in the remaining 55%.
- Long Sault is an 18 MW hydroelectric generating facility constructed in 1997. APUC acquired its interest in Long Sault by way of subscribing to two notes from the original partners. One of the original partners; an affiliate of APMI; was entitled to receive 5% of the equity cash flows commencing in 2014.
- Brampton Cogeneration is an energy supply facility which sells steam produced by EFW. In 2004, APMI acquired 50 Class B partnership units in BCI entitling them to 50% of the cash flow above 15% return on the investment.

18. Related party transactions (continued)

Equity interests in Rattle Brook, Long Sault, BCI (continued)

Effective December 31, 2013, APUC acquired the Parties' shares of Algonquin Power Corporation Inc. ("APC") which owns the partnership interest in the 18 MW Long Sault Rapids hydroelectric facility and the partnership interest in the Brampton cogeneration plant for an amount equal to $3,780. As APUC already consolidates Long Sault as a VIE, the acquisition of this partnership interest was treated as an equity transaction. The payment resulted in an adjustment to deferred tax liability of $10,692 in regards to tax attributes acquired with the partnership interests and an adjustment of $14,601 to equity of the shareholders of the Company as the partnership interests had a nominal carrying amount prior to the exchange.

In addition, APUC sold its 45% interest in the 4 MW Rattle Brook hydroelectric facility to the Parties for gross proceeds $3,408 for a loss on sale, net of tax of $422.

APUC earned a fee of $400 from APC during the year ended December 31, 2013 related to settlement of the related party transactions.

St. Leon LP Units

Third-party investors, including Senior Executives previously held 100 Class B limited partnership units issued by the St. Leon Limited Partnership which is the legal owner of the St. Leon Wind Facility.

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B limited partnership units (note 11) including 36 units held indirectly by Senior Executives. The Series C preferred shares provide dividends identical to what is expected from the Class B limited partnership units, as determined by independent consultants retained by the Independent Board Committee. As at January 1, 2013, no Senior Executives have any further direct or indirect ownership of the St. Leon Wind Facility.

Office Facilities

APUC has leased its head office facilities since 2001 on a triple net basis from an entity partially owned by the Senior Executives. Base lease costs for the year ended December 31, 2014 were $315 (2013 - $310). In the fourth quarter of 2014, APUC moved all head office employees into new premises and terminated the related party lease for nominal consideration. There is no further related party matter in relation to an office lease.

Chartered Aircraft

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into an agreement to charter aircraft in which the Senior Executives have a partial ownership. During the year ended December 31, 2013, APUC reimbursed direct costs in connection with the use of the aircraft of $472. As at December 31, 2013, the Independent Board Committee and the Parties agreed that all future utilization of chartered aircraft would be undertaken through a third-party charter operator at fair market value and under arrangements in which the Senior Executives have no interest. Final arrangements in this regard had not been completed as at December 31, 2014. During the year ended December 31, 2014, APUC reimbursed direct costs in connection with the use of the aircraft of $709.

Trafalgar

The Company owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, Trafalgar went into default under its debt obligations and an affiliate of APMI moved to foreclose on the assets. Subsequently Trafalgar went into bankruptcy. APUC and the affiliate of APMI have been jointly involved in litigation and in bankruptcy proceedings with Trafalgar since 2004. APMI initially funded $2 million in legal fees prior to 2004.

In 2004, the Company reimbursed APMI $1 million of the total third-party legal fees (which to that point totalled $2 million), and APUC agreed to fund future legal fees, third-party costs and other liabilities. It was agreed that any net proceeds from the lawsuits would be shared proportionally to the quantum of net costs funded by each party.

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

18. Related party transactions (continued)

Other related party transactions

A member of the Board is an executive at Emera. Related party transactions between APUC and Emera are discussed below:

- For the year ended December 31, 2014, the Company sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $5,780 (2013 - U.S. $6,042). 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. For the year ended December 31, 2014, the Company purchased natural gas amounting to U.S. $5,006 (2013 - U.S. $1,304) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction.
- In 2011, APUC provided a corporate guarantee in an amount of U.S. $1,000 to a subsidiary of Emera providing lead market participant services for fuel capacity and forward reserve markets to ISO NE for the Windsor Locks facility. There has not been any transaction under this contract in the last three years.

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

Other

A spouse of one of the Senior Executives provided market research consulting services to certain subsidiaries of the Company. During the year ended December 31, 2014 APUC paid $192 (2013 - $45) in relation to these services.

19. Non-controlling interests

Net loss attributable to non-controlling interests consists of the following:

	2014	2013
Net earnings attributable to Class B partnership units of Wind Portfolio SponsorCo	**$ 3,484**	$ 9,556
Net loss attributable to Class A partnership units	**(27,199)**	(20,408)
Other net earnings attributable to non-controlling interests	**1,529**	39
Total net loss attributable to non-controlling interests	**$ (22,186)**	$ (10,813)

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

The non-controlling Class A membership equity investors ("Class A partnership units") of Wind Portfolio SponsorCo and of the Bakersfield Solar Project, beginning December 31, 2014 are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the non-controlling interest holders in these subsidiaries is calculated using the HLBV method of accounting as described in note 1(t).

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

20. 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% (2013 - 26.5%). The differences are as follows:

	2014	2013
Expected income tax expense at Canadian statutory rate	**$ 19,199**	$ 16,072
Increase (decrease) resulting from:		
Recognition of deferred credit	**(5,763)**	(6,676)
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates	**(1,677)**	(2,338)
Non-taxable corporate dividend	**(2,618)**	(2,896)
Non-controlling interests share of income	**8,824**	4,266
Production tax credit	**(339)**	(247)
Allowance for equity funds used during construction	**(746)**	(694)
State taxes	**604**	313
Other	**(677)**	1,355
Income tax expense	**$ 16,807**	$ 9,155

For the years ended December 31, 2014 and 2013, earnings from continuing operations before income taxes consists of the following:

	2014	2013
Canadian operations	**$ 11,930**	$ 19,687
U.S. operations	**60,519**	40,962
	$ 72,449	$ 60,649

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

	Current	Deferred	Total
Year ended December 31, 2014			
Canada	$ 5,660	$ (3,538)	$ 2,122
United States	(1,986)	16,671	14,685
	$ 3,674	$ 13,133	$ 16,807
Year ended December 31, 2013			
Canada	$ 1,532	$ 881	$ 2,413
United States	994	5,748	6,742
	$ 2,526	$ 6,629	$ 9,155

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

20. 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 as of December 31, 2014 and 2013 are presented below:

	2014	2013
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	$ **319,056**	$ 226,314
Pension and OPEB	**54,458**	31,433
Acquisition related costs	**5,168**	5,152
Environmental obligation	**28,555**	23,076
Production tax credit	**2,098**	1,633
Reserves not currently deductible	**2,315**	2,397
Other	**3,988**	2,780
Total deferred income tax assets	**415,638**	292,785
Less valuation allowance	**(15,534)**	(15,667)
Total deferred tax assets	**400,104**	277,118
Deferred tax liabilities:		
Property, plant and equipment	**(387,931)**	(267,344)
Intangible assets	**(2,752)**	(8,321)
Outside basis in partnership	**(15,194)**	(2,210)
Regulatory accounts	**(49,399)**	(24,745)
Financial derivatives	**(15,013)**	(7,675)
Total deferred tax liabilities	**(470,289)**	(310,295)
Net deferred tax liabilities	$ **(70,185)**	$ (33,177)

The valuation allowance for deferred tax assets as at December 31, 2014 was $(15,534) (2013 - $(15,667)). The valuation allowance primarily relates 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:

	2014	2013
Current deferred income tax asset	$ **7,210**	$ 19,652
Non-current deferred income tax asset	**57,065**	86,632
Current deferred income tax liability	**(3,702)**	(2,308)
Non-current deferred income tax liability	**(130,758)**	(137,153)
	$ **(70,185)**	$ (33,177)

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

20. Income taxes (continued)

As of December 31, 2014, 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 loss carryforwards	
2015	$	5,426
2016 and onwards		733,022
	$	738,448

On October 27, 2009, unitholders of Algonquin Power Income Fund exchanged their trust units on a one-for-one basis for common shares of APUC (the "Unit Exchange Transaction"). As a result of the Unit Exchange Transaction, APUC recorded certain additional tax attributes to the extent management believed they were more likely than not to be realized. The excess of the carrying amount of the tax attributes assumed over the consideration paid was recorded as a deferred credit of $55,647 on the date of the Unit Exchange Transaction (the "Transaction Date"). The deferred credit has been recognized into income as a deferred income tax recovery in relative proportion to the amount of the related tax attributes that have been utilized since the Transaction Date.

Subsequent to the balance sheet date, APUC received a proposal letter from the Canada Revenue Agency ("CRA") which outlines its intention to challenge the tax consequences of the Unit Exchange Transaction. CRA is seeking to apply the acquisition of control rules or the general anti-avoidance rules of the Income Tax Act (Canada) the effect of which would be to deny APUC of the benefit of the tax attributes assumed as part of the Unit Exchange Transaction.

Should APUC receive a Notice of Reassessment covering the 2009, 2010, 2011, 2012 and 2013 taxation years, APUC will be required to make a deposit payment of 50% of the tax liability (including interest and any applicable penalties) claimed by the CRA in order to appeal the expected reassessment. Based on the tax amounts related to the 2009 to 2013 taxation years, that payment amount would be approximately $17,500. Additionally, assuming 2014 return will be similarly reassessed, a further payment of approximately $3,100 would also be required. APUC would also be required to make a deposit payment of 50% of the taxes the CRA claims are owed in any future tax year if the CRA were to issue a similar Notice of Reassessment for such years and APUC were to appeal it.

Should APUC be successful in defending its position, all such payments plus applicable interest, will be refunded to APUC. If the CRA is successful, APUC would be required to pay the balance of the taxes assessed, plus interest and penalties.

APUC remains confident in the appropriateness of its tax filing position and the expected tax consequences of the Unit Exchange Transaction and intends to vigorously defend such position. APUC strongly believes that the acquisition of control or the general anti-avoidance rules do not apply to the Unit Exchange Transaction and intends to file its future tax returns on a basis consistent with its previous tax returns. As a result, the probability of any potential final cash payment and impact on net earnings cannot be estimated at this time, but could range from $nil to $45,000.

The impact of the proposal on APUC's tax provision has been considered by management; however, management continues to believe that the most likely outcome has not changed and it is more likely than not, that APUC will be successful in defending its position. On this basis, APUC's 2014 financial statements do not include the impact of a potential reassessment. Until the matter is resolved with CRA, or should new facts arise that would result in a change to management's assessment of the most likely outcome, any future deposit tax payments made by APUC will be recorded to the consolidated balance sheets and will not impact net earnings.

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

21. 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 and subscription receipts issued (note 14 (a)(iii)) during the year. Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts issued, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs and DSUs outstanding during the period and, if dilutive, potential incremental common shares issuable upon the exercise of stock options. The dilutive effect of outstanding stock options is reflected in diluted earnings per share by application of the treasury stock method.

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

	2014	2013
Net earnings attributable to shareholders of APUC	**$ 75,701**	$ 20,296
Series A Preferred shares dividend	**5,400**	5,400
Series D Preferred shares dividend	**4,103**	—
Net earnings attributable to common shareholders of APUC	**$ 66,198**	$ 14,896
Discontinued operations	**(2,127)**	(42,011)
Net earnings attributable to common shareholders of APUC from continuing operations - Basic and Diluted	**$ 68,325**	$ 56,907
Weighted average number of shares		
Basic	**213,953,870**	204,350,689
Effect of dilutive securities	**2,387,722**	1,482,515
Diluted	**216,341,592**	205,833,204

The shares potentially issuable as a result of 1,786,401 stock options (2013 – 885,418) are excluded from this calculation as they are anti-dilutive.

22. Segmented information

During the fourth quarter, the Company aligned its management reporting under three business units - Generation, Transmission and Distribution. As a result, APUC has four reporting segments. Under Generation, the Company owns or has interests in hydroelectric, solar and wind power facilities which are aggregated as the renewable segment and operates co-generation, steam production and other thermal facilities which are aggregated as the thermal segment. The Distribution reporting segment now aggregates the electric, natural gas and water distribution utilities into a single reporting segment. Finally, the Transmission reporting segment, invests in rate regulated electric transmission and natural gas pipeline systems.

The operating segments were aggregated as generation (renewable, thermal), distribution and transmission based on their economic characteristics. The Transmission segment includes the new equity method investment in the Natural Gas Pipeline Development (note 8(b)) which is not yet significant and as a result is not presented separately in the tables below.

For purposes of evaluating divisional performance, the Company allocates the realized portion of any gains or losses on financial instruments to specific divisions. The unrealized portion of any gains or losses on derivative instruments not designated in a hedging relationship is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The results of operations and assets for these new segments are reflected in the tables below. The comparative information for 2013 has been reclassified to conform with the composition of the reporting segments presented in the current year.

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

22. Segmented information (continued)

	Year ended December 31, 2014					
	Generation			Distribution	Corporate	Total
	Renewable	Thermal	Total			
Revenue						
Regulated electricity distribution	$ —	$ —	$ —	$ 206,667	$ —	$ 206,667
Regulated gas distribution	—	—	—	446,025	—	446,025
Regulated water reclamation and distribution	—	—	—	66,419	—	66,419
Non-regulated energy sales	159,400	42,900	202,300	—	—	202,300
Other revenue	13,257	3,208	16,465	5,684	—	22,149
Total revenue	172,657	46,108	218,765	724,795	—	943,560
Operating expenses	46,077	9,405	55,482	180,442	60	235,984
Regulated electricity purchased	—	—	—	120,506	—	120,506
Regulated gas purchased	—	—	—	261,116	—	261,116
Non-regulated energy purchased	16,676	22,588	39,264	—	—	39,264
	109,904	14,115	124,019	162,731	(60)	286,690
Administrative expenses	(13,120)	(337)	(13,457)	(19,947)	(1,288)	(34,692)
Depreciation of property, plant and equipment	(48,479)	(5,980)	(54,459)	(52,387)	(2,128)	(108,974)
Amortization of intangible assets	(2,979)	(891)	(3,870)	(756)	—	(4,626)
Other amortization	81	—	81	(528)	—	(447)
Gain on foreign exchange	—	—	—	—	1,112	1,112
Interest expense	(32,117)	(1,751)	(33,868)	(27,139)	(1,411)	(62,418)
Interest, dividend income and other income	1,683	(496)	1,187	3,369	3,202	7,758
Gain on sale of asset	110	326	436	—		436
Acquisition-related costs	—	—	—	—	(2,552)	(2,552)
Write-down of long-lived assets	—	(698)	(698)	(300)	(7,465)	(8,463)
Gain (loss) on derivative financial instruments	214	—	214	—	(1,589)	(1,375)
Earnings from continuing operations before income taxes	15,297	4,288	19,585	65,043	(12,179)	72,449
Loss from discontinued operations before income taxes	(3,189)	(216)	(3,405)	—	—	(3,405)
Earnings (loss) before income taxes	$ 12,108	$ 4,072	$ 16,180	$ 65,043	$ (12,179)	$ 69,044
Property, plant and equipment	$1,602,465	$ 85,000	$1,687,465	$1,531,166	$ 59,791	$3,278,422
Equity-method investees	2,267	1,253	3,520	1,563	1,652	6,735
Total assets	1,795,757	100,603	1,896,360	2,106,638	111,417	4,114,415
Capital expenditures	197,051	4,012	201,063	176,849	54,461	432,373
Acquisition of operating entities	—	—	—	8,757	—	8,757

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

22. Segmented information (continued)

	Year ended December 31, 2013					
	Generation			Distribution	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Regulated electricity distribution	$ —	$ —	$ —	$ 166,156	$ —	$ 166,156
Regulated gas distribution	—	—	—	260,424	—	260,424
Regulated water reclamation and distribution	—	—	—	57,350	—	57,350
Non-regulated energy sales	145,661	34,530	180,191	—	—	180,191
Other revenue	7,058	2,442	9,500	1,270	400	11,170
Total revenue	152,719	36,972	189,691	485,200	400	675,291
Operating expenses	40,282	8,514	48,796	131,550	—	180,346
Regulated electricity purchased	—	—	—	97,376	—	97,376
Regulated gas purchased	—	—	—	148,784	—	148,784
Non-regulated energy purchased	8,684	17,151	25,835	—	—	25,835
	103,753	11,307	115,060	107,490	400	222,950
Administrative expenses	(13,094)	(223)	(13,317)	(7,477)	(2,724)	(23,518)
Depreciation of property, plant and equipment	(45,122)	(5,439)	(50,561)	(41,417)	—	(91,978)
Amortization of intangible assets	(2,652)	(856)	(3,508)	(692)	—	(4,200)
Other amortization	81	—	81	78	—	159
Gain on foreign exchange	—	—	—	—	567	567
Interest expense	(27,472)	(1,046)	(28,518)	(23,734)	(1,174)	(53,426)
Interest, dividend income and other income	1,867	193	2,060	3,228	2,497	7,785
Loss on sale of asset	(750)	—	(750)	—	—	(750)
Acquisition-related costs	—	—	—	—	(2,140)	(2,140)
Gain (loss) on derivative financial instruments	(767)	—	(767)	—	5,967	5,200
Earnings from continuing operations before income taxes	15,844	3,936	19,780	37,476	3,393	60,649
Loss from discontinued operations before income taxes	1,128	(61,630)	(60,502)	—	—	(60,502)
Earnings (loss) before income taxes	$ 16,972	$ (57,694)	$ (40,722)	$ 37,476	$ 3,393	$ 147
Property, plant and equipment	$1,364,843	$ 79,828	$1,444,671	$1,264,033	$ —	$2,708,704
Equity-method investees	—	1,718	1,718	325	8,623	10,666
Total assets	1,492,144	116,922	1,609,066	1,673,631	193,784	3,476,481
Capital expenditures	46,885	2,631	49,516	108,861	—	158,377
Acquisition of operating entities	2,083	—	2,083	236,931	—	239,014

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

22. 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 2014 or 2013: Hydro Québec 11% (2013 - 14%) and Manitoba Hydro 13% (2013 - 14%). The Company has mitigated its credit risk to the extent possible by selling energy to large utilities in various North American locations.

APUC operates in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2014	2013
Revenue		
Canada	**$ 92,267**	$ 65,380
United States	**851,293**	609,911
	$ 943,560	$ 675,291
Property, plant and equipment		
Canada	**$ 590,580**	$ 433,153
United States	**2,687,842**	2,275,551
	$ 3,278,422	$ 2,708,704
Intangible assets		
Canada	**$ 25,601**	$ 26,802
United States	**28,410**	27,614
	$ 54,011	$ 54,416

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

23. 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 Quebec Court of Appeal ordered a subsidiary of APUC to pay approximately $5,400 (including interest) to the Government of Quebec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6,400. In 2012, the Company paid an amount of $1,884 to the government of Quebec 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.

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

23. Commitments and contingencies (continued)

(a) Contingencies (continued)

(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, the New Hampshire Department of Environmental Services and the Massachusetts Department of Environmental Protection.

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

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

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $72,594 which at discount rates ranging from 2.1% to 3.4% represents the recorded accrual of $72,305 as of December 31, 2014 (December 31, 2013 - $69,555).

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, as of December 31, 2014, the Company has reflected a regulatory asset of $102,735 (December 31, 2013 - $85,029) for the MGP and related sites (note 7(a)).

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

2015	$ 19,643
2016	22,229
2017	14,394
2018	5,443
2019	629
Thereafter to 2046	10,256
	$ 72,594

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 8, the following significant commitments exist as of December 31, 2014.

As a result of the dam safety legislation passed in Quebec (Bill C-93), APUC has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. The assessments have identified a number of remedial measures required to meet the new safety standards. APUC currently estimates further capital expenditures of approximately $7,900 over a period of five years related to compliance with the legislation.

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

23. Commitments and contingencies (continued)

(b) Commitments (continued)

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

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Purchased power	$118,158	$ —	$ —	$ —	$ —	$ —	$ 118,158
Gas delivery, service and supply agreements	52,848	37,714	30,318	27,718	27,625	88,234	264,457
Service agreements	28,572	32,147	32,537	31,556	31,382	481,061	637,255
Capital projects	21,972	—	—	—	—	—	21,972
Operating leases	5,647	4,951	4,604	4,274	4,190	97,421	121,087
Total	$227,197	$ 74,812	$67,459	$63,548	$63,197	$666,716	$1,162,929

Calpeco Electric System 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, 2014. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism. Granite State Electric System 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.

24. Non-cash operating items

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

	2014	2013
Accounts receivable	**$ 2,572**	$ (213)
Prepaid expenses	**36**	(11)
Accrued liabilities	**(1,346)**	260
	$ 1,262	$ 36

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

	2014	2013
Accounts receivable	**$ (23,640)**	$ (49,888)
Related party balances	**—**	(996)
Natural gas in storage	**(5,942)**	(6,330)
Supplies and consumable inventory	**(3,861)**	(525)
Income taxes receivable	**(189)**	177
Prepaid expenses	**827**	(485)
Accounts payable	**54,299**	(29,292)
Accrued liabilities	**32,520**	37,023
Current income tax liability	**(1,527)**	1,399
Net regulatory assets and liabilities	**(54,277)**	1,098
	$ (1,790)	$ (47,819)

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

25. Financial instruments

(a) Fair value of financial instruments

2014	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 39,510	$ 41,339	$ —	$ 41,339	$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	41,966	41,966	—	—	41,966
Energy contracts not designated as a cash flow hedge	504	504	—	—	504
Total derivative financial instruments	42,470	42,470	—	—	42,470
Total financial assets	$ 81,980	$ 83,809	$ —	$ 41,339	$ 42,470
Long-term liabilities	$ 1,280,023	$ 1,363,934	$ 520,142	$ 843,792	$ —
Preferred shares, Series C	18,693	18,209	—	18,209	—
Derivative financial instruments:					
Cross-currency swap designated as a net investment hedge	36,276	36,276	—	36,276	—
Interest rate swap designated as a hedge	4,684	4,684	—	4,684	—
Interest rate swaps not designated as a hedge	1,383	1,383	—	1,383	—
Commodity contracts for regulated operations	2,928	2,928	—	2,928	—
Total derivative financial instruments	45,271	45,271	—	45,271	—
Total financial liabilities	$ 1,343,987	$ 1,427,414	$ 520,142	$ 907,272	$ —

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

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

2013	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 22,678	$ 26,321	$ —	$ 26,321	$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	31,971	31,971	—	—	31,971
Energy contracts not designated as a cash flow hedge	3,737	3,737	—	—	3,737
Cross-currency swap designated as a net investment hedge	109	109	—	109	—
Commodity contracts for regulatory operations	482	482	—	482	—
Total derivative financial instruments	36,299	36,299	—	591	35,708
Total financial assets	$ 58,977	$ 62,620	$ —	$ 26,912	$ 35,708
Long-term liabilities	$1,255,588	$1,261,340	$ 296,986	$ 964,354	$ —
Preferred shares, Series C	18,805	18,293		18,293	—
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	4,781	4,781	—	—	4,781
Cross-currency swap designated as a net investment hedge	7,947	7,947	—	7,947	—
Interest rate swaps not designated as a hedge	3,180	3,180	—	3,180	—
Commodity contracts for regulated operations	313	313	—	313	—
Total derivative financial instruments	16,221	16,221	—	11,440	4,781
Total financial liabilities	$1,290,614	$1,295,854	$ 296,986	$ 994,087	$ 4,781

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value as of December 31, 2014 and 2013 due to the short-term maturity of these instruments.

Notes receivable fair values (level 2) 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.

The Company's level 2 fair value of long-term liabilities at fixed interest rates and Series C preferred shares has been determined using a discounted cash flow method and current interest rates.

The Company's level 2 fair value derivative instruments primarily consist of swaps, options and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace.

The Red Lily conversion option is measured at fair value on a recurring basis using unobservable inputs (level 3). The fair value is based on an income approach using an option pricing model that includes various inputs such as energy yield function from wind, estimated cash flows and a discount rate of 9.0%. 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, 2014 or 2013.

The Company's level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from $16.62 to $113.93 with a weighted average of $39.72 as of December 31, 2014. The processes and methods of measurement are developed using the market knowledge of the trading operations within the Company and are derived from observable energy curves adjusted to reflect the illiquid market of the hedges and, in some cases, the variability in deliverable energy. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts are detailed in notes 25(b)(ii) and 25(b)(iv).

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

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2014 or 2013.

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

25. Financial instruments (continued)

(b) Derivative instruments

Derivative instruments are recognized on the consolidated balance sheets as either assets or liabilities and measured at fair value each reporting period.

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas service territories. The Company's strategy is to minimize fluctuations in gas sales prices to regulated customers.

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

	2014
Financial contracts: Gas swaps	1,774,018
Gas options	907,758
	2,681,776

The accounting for these derivative instruments is subject to 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 consolidated balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 7(d)). 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 consolidated balance sheets:

		2014		2013
Regulatory assets:				
Gas swap contracts	U.S. **$**	**2,178**	U.S. $	86
Gas option contracts	U.S. **$**	**346**	U.S. $	208
Regulatory liabilities:				
Gas swap contracts	U.S. **$**	**—**	U.S. $	416
Gas option contracts	U.S. **$**	**—**	U.S. $	37

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities and at one of its hydro facilities no longer subject to a power purchase agreement by entering into the following long-term energy derivative contracts.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)		Pay floating price (per MW-hr)
98,167	December 2016	$	67.91	AESO
915,428	December 2022	U.S. $	42.81	PJM Western HUB
3,907,711	December 2022	U.S. $	30.25	NI HUB
4,330,303	December 2027	U.S. $	36.46	ERCOT North HUB

On November 14, 2014, the Company entered into a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year $135,000 bond. The change in fair value resulted in a loss of $4,684 for the year ended December 31, 2014, which is recorded in OCI.

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

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The following table summarizes changes in OCI attributable to derivative financial instruments designated as a cash flow hedge:

		2014		2013
Effective portion of cash flow hedge, loss	**$**	**1,043**	$	18,940
Amortization on cash flow hedge		**(32)**		(30)
Loss (gain) reclassified from AOCI into non-regulated energy sales		**5,423**		(1,602)
	$	**6,434**	$	17,308
Less non-controlling interest		**5,982**		(9,064)
Change in OCI attributable to shareholders of APUC	**$**	**12,416**	$	8,244

The Company expects $10,132 of unrealized gains currently in AOCI to be reclassified into non-regulated energy sales 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 and $200,000 debenture offerings in December 2012 and January 2014, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Generation Group'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 U.S. dollar accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A loss of $28,537 (2013 - loss of $5,771) was recorded in OCI in 2014.

(iv) Other derivatives

The Company 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 classified as derivative instruments. The electricity derivative contracts are net settled fixed-for-floating swaps whereby APUC pays a fixed price and receives the floating or indexed price on a notional quantity of energy over the remainder of the contract term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)		Net Asset	
18,283	March 2015	U.S. $	57.53	$	417

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

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

The Company is party to an interest rate swap whereby, the Company pays a fixed interest rate of 4.47% on a notional amount of $60,513 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. As of December 31, 2014, the estimated fair value of the interest rate swap was a liability of $1,383 (2013 – liability of $3,180). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

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

The effects on the consolidated statements of operations of derivative financial instruments not designated as hedges consist of the following:

	2014	2013
Change in unrealized loss (gain) on derivative financial instruments:		
Interest rate swaps	**$ (1,797)**	$ (1,598)
Energy derivative contracts	**3,386**	(3,809)
Total change in unrealized loss (gain) on derivative financial instruments	**$ 1,589**	$ (5,407)
Realized loss (gain) on derivative financial instruments:		
Interest rate swaps	**1,962**	2,024
Energy derivative contracts	**(3,627)**	(466)
Total realized loss (gain) on derivative financial instruments	**$ (1,665)**	$ 1,558
Gain on derivative financial instruments not accounted for as hedges	**(76)**	(3,849)
Ineffective portion of derivative financial instruments accounted for as hedges	**1,451**	(1,351)
Loss (gain) on derivative financial instruments	**$ 1,375**	$ (5,200)

(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 of 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.

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

25. 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, notes receivable and derivative instruments. 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 Distribution Group which consists of water and wastewater utilities, electric utilities and gas utilities in the United States. In this regard, the credit risk related to Distribution Group accounts receivable balances of U.S. $119,866 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 Distribution Group allow for a reasonable bad debt expense to be incorporated in the rates and therefore recovered from rate payers.

As of December 31, 2014, the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2014	
	Canadian $	US $
Cash and cash equivalents and restricted cash	$ 5,823	$ 19,095
Accounts receivable	20,320	151,265
Allowance for doubtful accounts	—	(6,232)
Notes receivable	21,901	15,179
	$ 48,044	$ 179,307

In addition, the Company continuously monitors the creditworthiness of the counterparties to its foreign exchange, interest rate, and energy derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. The counterparties consist primarily of financial institutions. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

As of December 31, 2014, an amount receivable under the derivatives for Sandy Ridge, Senate and Minonk Wind Facilities of $156 (2013 - $7,344) was held as collateral by the counterparty.

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

25. 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 of December 31, 2014, in addition to cash on hand of $9,273 the Company had $485,927 available to be drawn on its senior debt facilities. Each of the Company's revolving 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	$ 9,130	$ 90,955	$ 218,795	$ 961,143	$ 1,280,023
Advances in aid of construction	1,149	—	—	79,955	81,104
Interest on long-term debt	64,232	125,268	102,070	146,689	438,259
Purchase obligations	267,914				267,914
Environmental obligation	19,643	36,623	6,072	10,256	72,594
Derivative financial instruments:					
Cross-currency swap	1,463	2,975	2,433	29,405	36,276
Interest rate forwards	—	—	4,684	—	4,684
Interest rate swaps	1,383	—	—	—	1,383
Energy derivative and commodity contracts	2,337	591	—	—	2,928
Other obligations	9,873	860	25	29,659	40,417
Total obligations	$ 377,124	$ 257,272	$ 334,079	$1,257,107	$ 2,225,582

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.

The Company designates the amounts drawn on the Generation Group's revolving credit facility denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in the Generation Group's U.S. operations. The foreign currency transaction gain or loss on the outstanding U.S. dollar denominated balance of the facility that is designated as a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in OCI) related to the net investment, to the extent it is effective as a hedge. A foreign currency loss of $2,727 for the year-ended December 31, 2014 (2013 - $1,607) was recorded in OCI.

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

26. Comparative figures

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

NOTES

NOTES

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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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Masheed Saidi – Former Executive VP and Chief Operating Officer, US Transmission, National Grid USA
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