UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

[Check one]

¨ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

x **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2012 **Commission File Number** 000-53808

ALGONQUIN POWER & UTILITIES CORP.

(Exact name of Registrant as specified in its charter)

N/A
(Translation of Registrant's name into English (if applicable))

Canada
(Province or other jurisdiction of incorporation or organization)

4911
(Primary Standard Industrial Classification Code Number (if applicable))

N/A
(I.R.S. Employer Identification Number (if applicable))

2845 Bristol Circle
Oakville, Ontario
L6H 7H7, Canada
(905) 465-4500
(Address and telephone number of Registrant's principal executive offices)

C T Corporation System
111 Eighth Avenue
New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
N/A	N/A

Securities registered or to be registered pursuant to Section 12(g) of the Act.

Common Shares, no par value
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

N/A
(Title of Class)

For annual reports, indicate by check mark the information filed with this form:

x **Annual Information Form** x **Audited Annual Financial Statements**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

As of December 31, 2012, there were 188,763,486 Common Shares outstanding.

Indicate by check mark whether the Registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the proceeding 12 months (or for such shorter period that the Registrant was required to file such reports); and (2) has been subject to such filing requirements in the past 90 days.

Yes x **No** ¨

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this Chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files)

Yes x **No** ¨

ANNUAL INFORMATION FORM

The Annual Information Form of Algonquin Power & Utilities Corp. ("Algonquin") for the fiscal year ended December 31, 2012 is filed as Exhibit 99.1 to this annual report on Form 40-F.

AUDITED ANNUAL FINANCIAL STATEMENTS

The Audited Annual Financial Statements of Algonquin for the fiscal year ended December 31, 2012 are filed as Exhibit 99.2 to this annual report on Form 40-F.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis for the fiscal year ended December 31, 2012 is filed as Exhibit 99.3 to this annual report on Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

The information provided under the heading "Disclosure Controls" (page 53) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2012, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

INTERNAL CONTROL OVER FINANCIAL REPORTING

a. Management's report on internal control over financial reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Algonquin'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 Algonquin's internal control over financial reporting as of December 31, 2012, based on the framework established in *Internal Control– Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that Algonquin maintained effective internal control over financial reporting as at December 31, 2012.

During the year ended December 31, 2012, Algonquin acquired Granite State Electric Company, EnergyNorth Natural Gas Inc., Liberty Energy (Midstates) Corp., Wind Portfolio SponsorCo LLC and Wind Portfolio Holdings LLC associated with total assets of $757.7 million and total revenues of $117.0 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2012. As permitted by the U.S. Securities and Exchange Commission, Management excluded these acquisitions from its evaluation of the effectiveness of the Company's internal controls over financial reporting as of December 31, 2012 due to the complexity associated with assessing internal controls during integration efforts and the proximity of certain of the acquisitions to year-end.

KPMG LLP, the independent registered public accounting firm of Algonquin, which audited the consolidated financial statements of Algonquin for the year ended December 31, 2012, has also issued an attestation report on the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2012.

b. Auditor's attestation report on internal control over financial reporting

The attestation report of KPMG LLP, the independent registered public accounting firm of Algonquin, on the Company's internal control over financial reporting as of December 31, 2012, is provided in Exhibit 99.2 to this annual report on Form 40-F.

c. Changes in internal control over financial reporting

The information provided under the heading "Internal controls over financial reporting" (page 53) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2012, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

AUDIT COMMITTEE FINANCIAL EXPERTS

Algonquin's board of directors has determined that it has three audit committee financial experts serving on its audit committee. Christopher Ball, Kenneth Moore and George Steeves have been determined to be such audit committee financial experts and are independent, as that term is defined by the Toronto Stock Exchange's listing standards applicable to Algonquin. The SEC has indicated that the designation of Christopher Ball, Kenneth Moore and George Steeves as audit committee financial experts does not make any of them an "expert" for any purpose, impose any duties, obligations or liability on Christopher Ball, Kenneth Moore and George Steeves that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee or board of directors.

CODE OF ETHICS

Algonquin has adopted a code of ethics (the "Code of Conduct") that applies to all employees and officers, including its Chief Executive Officer and Chief Financial Officer and Chief Accounting Officer. The Code of Conduct is available without charge to any shareholder upon request to Kelly Castledine, Telephone: (905) 465-4500, E-mail: ir@algonquinpower.com, Algonquin Power & Utilities Corp., 2845 Bristol Circle, Oakville, Ontario, L6H 7H7.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information provided under the heading "Pre-Approval Policies and Procedures" (page 104) in the Annual Information Form for the fiscal year ended December 31, 2012, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein. All audit services, audit-related services, tax services, and other services provided for the year ended December 31, 2012 were pre-approved by the audit committee.

OFF-BALANCE SHEET ARRANGEMENTS

Algonquin is not a party to any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on its financial condition, results of operations or cash flows.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The information provided under the heading "Contractual Obligations" (page 39) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2012, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

IDENTIFICATION OF THE AUDIT COMMITTEE

The information provided under the heading "Audit Committee" (page 103) identifying Algonquin's Audit Committee and confirming the independence of the Audit Committee in the Annual Information Form for the fiscal year ended December 31, 2012, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein.

NON-GAAP FINANCIAL MEASURES

Algonquin uses the terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA"), "adjusted funds from operations", "per share adjusted net earnings", "per share cash provided by adjusted funds from operations" and "per share cash provided by operating activities" throughout the Management's Discussion and Analysis for the fiscal year ended December 31, 2012 filed as Exhibit 99.3 to this annual report on Form 40-F. The terms "adjusted net earnings", "per share cash provided by operating activities", "adjusted funds from operations", "per share adjusted net earnings", "per share cash provided by adjusted funds from operations" and Adjusted EBITDA are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share adjusted net earnings", "per share cash provided by adjusted funds from operations" and "per share cash provided by operating activities". Consequently, Algonquin'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 adjusted net earnings", "per share cash provided by adjusted funds from operations" and "per share cash provided by operating activities" can be found throughout the Management's Discussion and Analysis.

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 Algonquin.

CAUTION CONCERNING FORWARD LOOKING STATEMENTS

Certain statements included in this annual report on Form 40-F and the exhibits attached hereto contain forward-looking information within the meaning of the United States Private Securities Litigation Reform Act of 1995 and applicable Canadian securities legislation. These statements reflect the views of Algonquin with respect to future events, based upon assumptions relating to, among others, the performance of Algonquin'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 Algonquin, its future plans and its dividends to shareholders. Statements containing expressions such as "outlook", "believe", "anticipate", "continue", "could", "expect", "may", "will", "project", "estimate", "intend", "plan" and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require Algonquin to make assumptions and involve inherent risks and uncertainties. Algonquin cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that Algonquin's actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the volatility of world financial markets; 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; the state of the Canadian and the United States economies and accompanying business climate as well as those risk factors discussed or referred to in the Management's Discussion and Analysis for the fiscal year ended December 31, 2012, filed as Exhibit 99.3 to this annual report on Form 40-F and the Annual Information Form for the fiscal year ended December 31, 2012, filed as Exhibit 99.1 to this annual report on Form 40-F. Algonquin cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Algonquin reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. Although Algonquin believes that the assumptions inherent in these forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of these dates. Algonquin 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.

MINE SAFETY DISCLOSURE

Not applicable.

INTERACTIVE DATA FILE

The required disclosure for the fiscal year ended December 31, 2012 is filed as Exhibit 101 to this annual report on Form 40-F.

UNDERTAKING

Algonquin undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

Algonquin previously filed with the Commission a written irrevocable consent and power of attorney on Form F-X.

Any change to the name or address of the agent for service of Algonquin shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of Algonquin.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

ALGONQUIN POWER & UTILITIES CORP.
(Registrant)

Date: March 28, 2013

By: /s/ David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer

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Exhibit	Description
99.1	Annual Information Form for the year ended December 31, 2012
99.2	Audited Annual Financial Statements for the year ended December 31, 2012
99.3	Management's Discussion & Analysis for the year ended December 31, 2012
99.4	Consent Letter from KPMG LLP, Chartered Accountants
99.5	Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
99.6	Certifications of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
99.7	Certifications of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.8	Certifications of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101	Interactive Data File

Exhibit 99.1



ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM

March 28, 2013

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All information contained in this Annual Information Form ("AIF") is presented as at March 28, 2013, unless otherwise specified. In this AIF, all dollar figures are in Canadian dollars, unless otherwise indicated.

Caution concerning forward-looking statements

Certain statements included in this AIF contain information that is forward-looking within the meaning of certain securities laws, including information and statements regarding prospective results of operations, financial position or cash flows. Forward-looking information is included throughout this Annual Information Form, including among other places, under the heading “General Development of the Business”, “Description of the Business” and “*Legal Proceedings and Regulatory Actions*”. These statements and information are forward-looking, and are based on factors or assumptions that were applied in drawing a conclusion or making a forecast or projection, including assumptions based on historical trends, current conditions and expected future developments, and other factors believed to be appropriate in the circumstances.

Since forward-looking statements relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. APUC cautions that although it is believed that the 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 those set out in this AIF under “Risk Factors. Readers are cautioned that such risks and uncertainties may cause APUC’s actual results to vary materially from those expressed in, or implied by, the forward-looking statements and information. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Other than as specifically required by law, APUC undertakes no obligation to update any forward-looking statements or information to reflect new information, subsequent or otherwise.

1. CORPORATE STRUCTURE

1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. (" **APUC**" or the "**Corporation**") was originally incorporated under the *Canada Business Corporations Act* ("**CBCA**") on August 1, 1988 as Traduction Militech Translation Inc. Pursuant to articles of amendment dated August 20, 1990 and January 24, 2007, the corporation amended its articles to change its name to Societe Hydrogenique Incorporée – Hydrogenics Corporation and Hydrogenics Corporation – Corporation Hydrogenique, respectively. Pursuant to a certificate and articles of arrangement dated October 27, 2009, the corporation, among other things, created a new class of common shares (the "**Common Shares**"), transferred its existing operations to a newly formed independent corporation and changed its name to Algonquin Power & Utilities Corp. The head and principal office of APUC is located at 2845 Bristol Circle, Oakville, Ontario, L6H 7H7. APUC contemporaneously acquired all of the outstanding trust units of Algonquin Power Co. ("**APCo**") (See *General Development of the Business – The Unit Exchange*).

APUC's principal holdings are its trust units ("**Trust Units**") of APCo and shares of Liberty Utilities Co. (" **Liberty Utilities**"). Liberty Utilities' businesses operate under three separately managed regions – Liberty Utilities (West), Liberty Utilities (Central), and Liberty Utilities (East).

Unless the context indicates otherwise, references in this AIF to " **APUC**" include, for reporting purposes only, the direct or indirect subsidiary entities of APUC and partnership interests held by APUC and its subsidiary entities. Such use of "**APUC**" to refer to these other legal entities and partnership interests does not constitute a waiver by APUC or such entities or partnerships of their separate legal status, for any purpose.

1.2 Intercorporate Relationships

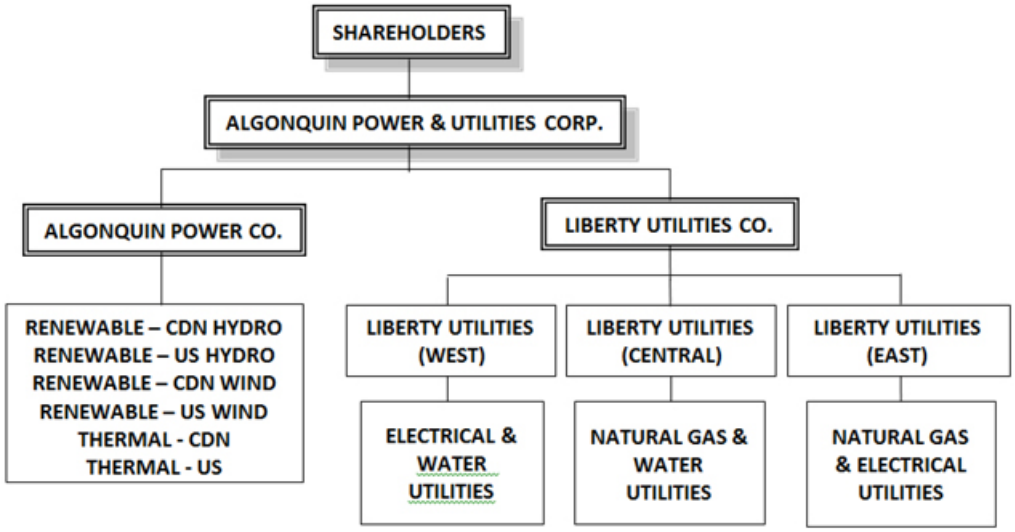
(a) **Subsidiaries**

The subsidiaries of APUC are grouped into the independent power generation and the utilities businesses. The principal holding for APUC's independent power generation business is an investment in 100% of the issued and outstanding Trust Units of APCo. The principal holding for APUC's utilities business is an investment in 100% of the issued and outstanding common shares of Liberty Utilities (Canada) Corp., a federal corporation, which in turn owns all of the issued and outstanding common shares of Liberty Utilities (America) Co., a Delaware corporation, which in turn owns all of the issued and outstanding common shares of Liberty Utilities (America) Holdco Inc., a Delaware corporation, which in turn owns all of the issued and outstanding shares of Liberty Utilities, a Delaware corporation, which in turn owns and operates the entities within the Liberty Utilities (West), Liberty Utilities (Central), and Liberty Utilities (East) regions. Each of APCo, Liberty Utilities (West), Liberty Utilities (Central), and Liberty Utilities (East) regions have their own subsidiaries and ownership chains.

The subsidiaries of APCo include the ownership chains of Algonquin Power Trust (" **APT**"), and Algonquin Power Fund (Canada) Inc. (" **APFC**"). APT's subsidiaries include the ownership chain of Algonquin Power Operating Trust ("**APOT**"), and APFC's subsidiaries include the ownership chain of Algonquin Power Fund (America) Inc. ("**APFA**"). The Liberty Utilities operating regions include Liberty Utilities (West), a region currently holding an electrical distribution utility located

in California, and water distribution and wastewater treatment utilities located in Arizona. The Liberty Utilities (Central) region currently holds water distribution and wastewater treatment utilities located in Arkansas, Illinois, Missouri, and Texas, and natural gas utilities located in Illinois, Iowa, and Missouri. The Liberty Utilities (East) region holds an electrical distribution utility and a natural gas distribution utility located in New Hampshire.

The following chart summarizes the principal operating subsidiaries of the Corporation and their major lines of business.



The major chains are defined below, including a detailed description of the legal entities that comprise these chains and the facilities they own. Additional information on the facilities is described in Schedules A, B, C, D, and E.

(i) Independent Power Generation Business – APCo Chain

APCo Chain Entities

APCo is the sole beneficiary of APT. APCo also owns Algonquin Holdco Inc., an Ontario corporation, which owns 68.9% of APFC, and 62.5% of the issued and outstanding shares of Cornwall Solar Inc.

APT Group

APT forms part of the APCo business unit. APT is an unincorporated open ended trust created by a declaration of trust dated June 30, 2000 in accordance with the laws of the Province of Ontario. APT owns all the Trust Units of APOT.

APT controls the entities that own some of the Canadian hydroelectric facilities, and indirectly owns the energy-from-waste facility (the " **EFW Facility**") located in the Regional Municipality of Peel, Ontario (" **Peel**") by virtue of owning all the Trust Units in KMS Power Income Fund, an unincorporated open ended trust created by a declaration of trust dated February 18, 1997 in accordance with the laws of the Province of Alberta. This trust owns Algonquin Power Energy From Waste Inc. ("**APEFW**"), an Ontario corporation that owns the EFW Facility.

APT also holds interests in certain of APCo's Canadian hydroelectric Facilities. It directly owns the hydroelectric Hydraska Facility and the Arthurville Facility, and owns both the general partnership and the limited partnership interests in Algonquin Power (Campbellford) Limited Partnership ("**Campbellford LP**"), an Ontario limited partnership which operates a 4 megawatt (" **MW**") hydroelectric generation station on the Trent River near Campbellford, Ontario (the "**Campbellford Facility**"). APT also directly owns a 42% limited partnership interest in the Algonquin Power (Mont-Laurier) Limited Partnership (the "**Mont-Laurier Partnership**"), a Québec limited partnership, which owns the Mont-Laurier facility and the Côte Ste.-Catherine facility. APEFW owns the remaining 58% partnership interests, comprised of a 46.5% limited partnership interest and an 11.5% general partnership interest.

APT owns Corporation D'Investissements Éoliennes Algonquin Power (" **Éoliennes**"), a Canadian corporation. Éoliennes indirectly owns St. Ulric Wind Energy Investments L.P. ("**St. Ulrich LP** "), a Québec limited partnership, through its ownership of the limited partnership of St. Ulrich LP and Société en Commandite Algonquin (Éoliennes), a Québec limited partnership, and its direct ownership of the general partner of St. Ulrich LP, named Corporation D'Investissements Éoliens St-Laurent Inc. ("**Corporation St-Laurent**"), a Québec corporation. Corporation St-Laurent is the 50% owner of Saint-Damase Wind Energy Fleur de Lis General Partner Corporation, a federal corporation, which is the general partner of the partnership known as Saint-Damase Wind Energy Fleur de Lis Limited Partnership ("**St. Damase LP** "). St. Damase LP has an interest in the Saint – Damase wind energy project and described below in "*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development – Current Development Projects*". St. Ulrich LP owns a 49.995% equity interest in the St. Damase LP, the general partner owns a .01% equity interest, and a non-Algonquin party owns the remaining 49.995% equity interest. APT also has an interest in Éoliennes Belle- Rivière, société en commandite ("**Belle Rivière**"), a Quebec partnership and the owner of the Val- Éo wind energy project, also described below in "*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development – Current Development Projects*". It owns a 25% equity interest in the general partner, 9231-5498 Québec Inc. and it also holds a 24.995% limited partner interest.

APOT Group

APOT is an unincorporated open ended trust created by an amended and restated trust indenture effective January 2, 1997, in accordance with the laws of the Province of Alberta.

APOT controls the entities that own the Canadian cogeneration facility located at Brampton, Ontario (the " **BCI Facility**"). The BCI Facility is owned by Brampton Cogeneration Limited Partnership, an Ontario partnership, the partners of which are Brampton Cogeneration Inc. ("**BCI**"), which is the general partner and holds one general partnership unit, and APOT, which owns 100% of the Class A Units (entitled to vote on all matters) and 50% of the Class B Units (vote on only specific matters) in the limited partnership. BCI is an Ontario corporation and is owned by APOT.

APOT controls the entities that own the 104 MW wind facility located at St. Leon, Manitoba (the " **St. Leon Facility**"). The APOT entity that owns the St. Leon Facility is St. Leon Wind Energy LP, an Ontario partnership ("**St. Leon LP**"). St. Leon LP is owned by its general partner, St. Leon Wind Energy GP Inc. ("**St. Leon GP**"), by St. Leon Wind Energy Trust, a Manitoba trust (" **St. Leon Trust**") and by AirSource Power Fund I LP, a Manitoba limited partnership ("**AirSource**"). St. Leon LP holds a 30.11% interest in APFC. St. Leon LP has also issued 100 Class B limited partnership units which were acquired by APUC on January 1, 2013 in exchange for newly issued APUC Class C Preferred Shares. St. Leon Trust is owned 100% by AirSource, the limited partner of which is Algonquin (AirSource) Power LP ("**AAP LP**") which holds a 99.99% interest in the limited partnership, and which in turn is owned 99.99% by APOT as limited partner. APOT also controls the general partner of AAP LP, AirSource Power Fund GP Inc, a Canadian corporation. AirSource is also the 100% owner of St. Leon GP. St. Leon GP is a Canadian corporation and St. Leon Trust is a trust created by a declaration of trust dated June 28, 2005 in accordance with the laws of the Province of Manitoba. The AirSource and AAP LP limited partnerships were formed in Manitoba and Ontario, respectively.

St. Leon GP also owns 100% of the ownership interests in St. Leon II Wind Energy LP (" **St. Leon II**"), a Manitoba partnership, the general partner of which is St. Leon II Wind Energy GP Inc., a Manitoba corporation, which is also owned by St. Leon LP. St. Leon II owns the 16.5 MW wind facility (the "**St. Leon II Facility**"), an expansion of the St. Leon Facility, located at St. Leon, Manitoba.

APOT is the sole limited partner in Red Lily Wind Power II Limited Partnership, a Saskatchewan limited partnership, the general partner of which is Red Lily Wind Power II GP Inc., a Saskatchewan corporation, which is also owned by APOT. APOT also owns Loyalist Wind Project GP Inc., an Ontario corporation, which is the general partner, holding 0.01% interest in Loyalist Wind Project LP ("**Loyalist LP**"), an Ontario limited partnership. APUC is the majority limited partner of Loyalist LP, holding the remaining 99.99% interest.

APOT has two ownership interests in Alberta. First, it is the beneficial owner of one hydroelectric facility in Alberta (the " **Dickson Dam Facility**"). APOT owns 50% of Valley Power Corp., an Ontario corporation, which holds a 0.0001% limited partnership interest partner in Valley Power LP, an Alberta limited partnership which owns the Alberta biomass facility (the "**Valley Power Facility**"). APOT also directly holds a 49.9995% limited partnership interest in Valley Power LP.

APFC Group

APFC, a subsidiary of APUC, is an Ontario corporation and it controls the entities that own the majority of APUC's hydroelectric facilities in Canada. APFC owns Algonquin Power (America) Inc., ("**APA**") a Delaware corporation, which is the parent company of APCo's operations in the United States.

In Ontario, APFC directly owns the Burgess and Hurdman Facilities, and has an agreement in place to buy ownership interests in the parties to the joint venture that owns the interests in the Long Sault Rapids facility. In Québec, APFC directly owns the facilities known as Rawdon, Hydro Snemo, St. Raphael, Belleterre and St. Brigette Facilities. APFC also holds a direct interest in Société Hydro-Donnacona, S.E.N.C. (the "**S.E.N.C.**"), the owner of the Donnacona Facility. The S.E.N.C. is a Québec general partnership, and is owned 99.99% by APFC and 0.01% by Donnacona Holdings Inc., an Ontario corporation 100% owned by APFC. In Newfoundland, APFC holds a 45% partnership interest in the Algonquin Power (Rattlebrook)

Partnership, a Newfoundland partnership that owns the Rattlebrook Facility. APFC also owns 100% of Algonquin Power Services Canada Inc., a Canadian corporation that provides purchasing services to Canadian APCo entities.

APFC also owns 1631667 Alberta ULC, an Alberta unlimited liability corporation.

APFA Group

APFA, a Delaware corporation, is owned by APA. APFA owns or holds interest in the hydroelectric, thermal cogeneration, and wind energy entities and facilities in the U.S.

APFA owns Algonquin Power Sanger LLC (" **Sanger LLC**"), a California limited liability company, and Algonquin Power Windsor Locks LLC ("**Windsor LLC**"), a Connecticut limited liability company. These entities own the U.S. cogeneration Sanger and Windsor Locks facilities. Sanger LLC directly owns 100% of Dyna Fibers Inc., a California corporation that operates a hydro-mulch business at the Sanger facility site. APFA also owns KMS Crossroads, LLC, a Delaware limited liability corporation.

APFA indirectly owns numerous hydroelectric facilities through majority interests ranging from 99.7% to 99.99% in the subsidiaries described in this paragraph, with Algonquin Power Fund (America) Holdco Inc. ("**Algonquin Holdco**"), a Delaware corporation owned by APFA, holding the remaining interests. The Vermont partnership Moretown Hydro Energy Company owns the Moretown Facility. The New Hampshire limited partnerships Gregg Falls Hydroelectric Associates Limited Partnership, Pembroke Hydro Associates Limited Partnership and Mine Falls Limited Partnership own the Gregg Falls, Pembroke and Mine Falls Facilities, respectively.

APFA owns the New Hampshire limited liability company Clement Dam Hydroelectric, LLC which owns the Clement Dam Facility. The Franklin, Beaver Falls and Lakeport Facilities are owned by, respectively, Franklin Power, LLC, a New Hampshire company, Algonquin Power (Beaver Falls) LLC, a Delaware corporation and Lakeport Hydroelectric Corp., a New Hampshire corporation. Court Street Investments Inc. ("**Court Street**"), a Massachusetts corporation, is owned 100% by APFA and owns CSI Oswego Corp., a Delaware corporation, which is a partner in Oswego Hydro Partners L.P., the Delaware partnership that owns the Phoenix Facility. The other partner in this partnership is Oswego Energy Corp., a Delaware corporation, which is 100% owned by Oswego Power Company, Inc., a Massachusetts corporation, which in turn is 100% owned by APFA. The remaining hydroelectric facilities in the United States are the Great Falls and Lochmere Facilities. The Great Falls Facility is owned by the Great Falls Hydroelectric Company Limited Partnership, a Maryland limited partnership in which APFA holds a 98% limited partner interest. Great Falls Energy, LLC holds the remaining 2% general partner interest. Great Falls Energy, LLC is a Maryland limited liability company wholly owned by APFA. The Lochmere Facility is owned by the Indiana general partnership HDI Associates I, which is held 0.1% by Algonquin Holdco and 99.9% by APFA.

On March 14, 2013, affiliates of APCo entered into an agreement to sell the following facilities: Phoenix Facility, Beaver Falls Facility, Greggs Falls Facility, Pembroke Facility, Clement Facility, Franklin Facility, Lochmere Facility, Lakeport Facility, Mine Falls Facility, and Great Falls Facility. The sale is subject to certain regulatory approvals and other conditions precedent. The transaction is expected to close in 2013.

APFA owns Algonquin Tinker Gen Co. (" **Tinker Gen Co.**") and Algonquin Northern Maine Gen Co. (" **Northern Maine Gen Co.**"), both Wisconsin companies. Tinker Gen Co. is also registered

in New Brunswick, and Northern Maine Gen Co. is also registered in Maine. Tinker Gen Co. operates the 36.8MW of electrical generating assets in New Brunswick (the "**Tinker Assets**"), and Northern Maine Gen Co. is the owner of the Caribou and Squa Pan diesel facilities. APFA also 100% owns Algonquin Energy Services Inc., a Delaware corporation ("**AES**") that is also registered in Connecticut, District of Columbia, Maine, Maryland, New Brunswick and Ohio. AES provides the electrical energy requirements for commercial and industrial customers in northern Maine.

APFA owns a 60% equity interest in Wind Portfolio SponsorCo LLC (" **SponsorCo**"), a Delaware LLC; the remaining 40% interest is held by Gamesa Energy USA, LLC ("**Gamesa USA**"), an independent party unrelated to APUC. SponsorCo owns 100% of the Class B managing interests in Wind Portfolio Holdings, LLC ("**WP HoldCo**"), a Delaware LLC. Non-Algonquin partners, JPM Capital Corporation, Morgan Stanley Wind LLC, and Gear Wind LLC, collectively hold 100% of the non-managing Class A interest in WP HoldCo, which in turn owns Wind Energy Portfolio Holdings I, LLC ("**WE HoldCo**"). WE Holdco directly owns the three entities which each own separate wind projects in the USA. Sandy Ridge Wind, LLC, a Delaware LLC, owns the Sandy Ridge Wind Facility in Pennsylvania; Minonk Wind, LLC, a Delaware LLC, owns the Minonk wind facility in Illinois; and Senate Wind, LLC, a Delaware LLC, owns the Senate wind facility in Texas.

Through a chain of subsidiaries, APFA owns Shady Oaks Holdings, LLC, a Delaware LLC, which owns TianRun Shady Oaks, LLC, a Delaware LLC, which owns GSG6, LLC, a Delaware LLC, which owns the Shady Oaks wind facility in Illinois. These subsidiaries were acquired effective January 1, 2013.

APFC also 100% owns Algonquin Power Services America LLC, a Delaware corporation that provides purchasing services to APCo entities operating in the U.S.

(ii) **Utilities Business**

Liberty Utilities (West) & Liberty Utilities (Central) Region Water and Wastewater Utilities

Liberty Water Co. ("**Liberty Water**"), a Delaware company, is the parent company of the water and wastewater entities within the Liberty Utilities (West) and Liberty Utilities (Central) regions. On December 22, 2010, APCo completed a corporate reorganization involving Liberty Water wherein 100% of the issued and outstanding common shares of Liberty Water were transferred from APCo to Liberty Utilities.

Liberty Water indirectly owns the water and wastewater businesses located in Arizona, Texas, Missouri, Illinois and Arkansas, in each case through a 100% wholly-owned subsidiary, with the exception of Northwest Sewer Inc., which it owns directly and the Entrada Del Oro Sewer Company, Inc. ("**Entrada**") which it currently operates and in which it holds a beneficial interest in the shares of the company pending regulatory approval of its acquisition by Liberty Water. All of these 100% wholly-owned subsidiaries (except Northwest Sewer, Inc.) are currently conducting business as "Liberty Utilities"; however the actual legal names of the relevant entities are set out below.

In Arizona, the following Arizona corporations own the following facilities: Bella Vista Water Co., Inc. owns the Bella Vista Facility; Black Mountain Sewer Corporation owns the Black Mountain Facility; Gold Canyon Sewer Company owns the Gold Canyon facility; Litchfield Park Service Company owns the Litchfield facility; Northern Sunrise Water Company, Inc. owns the Northern

Sunrise facility; Rio Rico Utilities, Inc. owns the Rio Rico facility; and Southern Sunrise Water Company, Inc. owns the Southern Sunrise facility. Northwest Sewer, Inc., an Arizona corporation, has undertaken to a group of developers and homeowner's associations located to the west of Phoenix to apply for a Certificate of Convenience and Necessity and, if successful, operate a wastewater treatment utility in those areas. Entrada, discussed above, is an Arizona corporation, and it owns the beneficial interest in the Entrada Del Oro facility. In Texas, the following Texas corporations own the following facilities: Tall Timbers Utility Company, Inc. owns the Tall Timbers facility; Woodmark Utilities, Inc. owns the Woodmark facility; Algonquin Water Resources of Texas, LLC, a Texas limited liability company, owns water and wastewater treatment assets at the Holly Lake Ranch, Hill County, Piney Shores and The Villages (also known as "Big Eddy") Resorts; and Algonquin Seaside Resort, LLC., a Texas limited liability company, owns water and wastewater treatment assets at the Seaside Resort. In Missouri, Algonquin Water Resources of Missouri, LLC, a Missouri limited liability company, owns assets associated with the Holiday Hills, Ozark Mountain, Timbercreek resorts, the water utility in Noel, Missouri and a utility in eastern Missouri. In Illinois, Algonquin Water Resources of Illinois, LLC, an Illinois limited liability company, owns assets for the Fox River Resort.

Liberty Energy Utilities Co. ("**Liberty Energy**"), a Delaware corporation, is owned by Liberty Utilities. Liberty Energy owns Liberty Utilities (Pine Bluff Water) Inc., which owns and operates the Pine Bluff Water Facility located in Pine Bluff, Arkansas. This facility was acquired by Liberty Utilities on February 1, 2013.

Liberty Utilities (West) Region Electrical Distribution Utility

Liberty Energy owns California Pacific Utilities Ventures, LLC, a California limited liability company (" **CPUV**"), which in turn owns California Pacific Electric Company, LLC, a California limited liability company ("**Calpeco**"). Calpeco owns an electricity distribution utility in the Lake Tahoe basin and surrounding areas in California ("**California Utility**").

Liberty Utilities (Central) Region Natural Gas Distribution Utility

Liberty Energy also owns Liberty Energy (Midstates) Corp. (" **Liberty Midstates**"), a Missouri corporation. Liberty Midstates owns natural gas distribution utility assets in Missouri, Iowa and Illinois (the "**Midwest Gas Utilities**"). These assets were purchased from Atmos Energy Corporation ("**Atmos**") on August 1, 2012.

Liberty Utilities (East) Region Electrical Distribution and Natural Gas Distribution Utility

Liberty Energy also owns Liberty Energy Utilities (New Hampshire) Corp. (" **Liberty Energy (NH)**"), a Delaware corporation registered in New Hampshire. Liberty Energy Utilities (NH) owns Granite State Electric Company ("**Granite State Electric Utility**") and EnergyNorth Natural Gas Inc. ("**EnergyNorth Gas Utility**"). Both Granite State Electric Utility and EnergyNorth Gas Utility were acquired from National Grid USA ("**National Grid**") on July 3, 2012.

Liberty Energy also owns Liberty Energy (Georgia) Corp. (" **Liberty Georgia**"), a Georgia corporation. Liberty Georgia will own natural gas distribution utility assets in Georgia (the "**Georgia Utility**"). Liberty Georgia has entered into an agreement to acquire these assets from Atmos. The acquisition is expected to close on or about April 1, 2013.

(iii) **Other**

Outside of APCo, Liberty Utilities (West), Liberty Utilities (Central) and Liberty Utilities (East) and their respective subsidiary entities as described above, APUC beneficially owns, directly or indirectly 100% of the following: 3793257 Canada Inc. ("**3793257**"), a holding company incorporated under the CBCA; and Windlectric Inc. ("**Windlectric**"), a federal corporation that is developing various wind projects including one in Saskatchewan and one in Ontario.

APUC also owns the following group of special purpose financing companies, including 90% of Liberty Utilities Finance GP 1 (" **LU GP1**"), a Delaware general partnership. LU GP1 owns 99.9% of Liberty Utilities Finance GP 2 ("**LU GP2**"), a Delaware general partnership. The minority partner in both LU GP1 and LU GP2 is 3793257. LU GP2 owns Liberty Utilities Finance (Canada) ULC, an Alberta unlimited liability corporation which in turn owns Liberty Utilities Finance (US) LLC, a Delaware limited liability company. The above entities were formed as special purpose financing entities used in Liberty Utilities financings.

(b) **Other Interests in Energy Related Developments**

The Corporation also has notes receivable and equity in companies owning generating facilities as described below. APT owns 25% of the Class B non-voting shares issued by Cochrane Power Corporation, the owner of a combined cycle cogeneration facility located in Cochrane, Ontario. APT also owns 32.4% of the Class B non-voting shares in Kirkland Lake Power Corporation, an entity which burns natural gas and wood waste to generate electricity. APT also owns a 12.1% interest in Tranche A and Tranche B term loan interests issued by Chapais Energie, Société en Commandite ("**Chapais**") which owns a wood waste facility in Chapais, Québec. It also owns a 33.9% interest in the Class B non-voting preferred shares of Chapais. The loans bear interest at the rate of 10.789% and 4.91%, respectively.

In addition, APCo is entitled to a royalty in the form of cash flows generated by the Long Sault Rapids facility (the " **LSR Royalty Interest**"). It is also the owner of a 14.14% secured, subordinated note (the "**LSR Subordinate Note**") in the principal amount of $2,000,000 issued jointly and severally by Algonquin Power (Long Sault) Corporation Inc., Energy Acquisition (Long Sault) Ltd., Nicholls Holdings Inc. and Radtke Holdings Inc.

As of January 1, 2013 APUC owns the Class B limited partnership units of St. Leon Wind Energy LP, the legal owner of the St. Leon facility.

2. GENERAL DEVELOPMENT OF THE BUSINESS

2.1 General

(a) **The Unit Exchange**

APUC is incorporated under the *Canada Business Corporations* Act. This is the parent company to Algonquin Power Co. (" **APCo**") through a transaction (the "**Unit Exchange**") in which APCo's unitholders exchanged their Trust Units of APCo, on a one-for-one basis, for Common Shares of the Corporation. As a result of the Unit Exchange, APCo itself became a wholly-owned subsidiary of the Corporation and all of the unitholders of APCo became shareholders of the Corporation. The Unit Exchange did not result in any change to the underlying business operations of APCo and accordingly, for accounting purposes, the Corporation is considered a continuation of APCo.

(b) **Business Strategy**

APUC's business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation in the independent power and rate regulated utilities business sectors. APUC is committed to delivering a total shareholder return comprised of dividends augmented by capital appreciation arising through dividend growth supported by increasing cash flows and earnings. Through an emphasis on sustainable, long-view renewable power and utility investments, over a medium-term planning horizon, APUC strives to deliver annualized per share earnings growth of more than 5% and continued growth in its dividend supported by these increasing cash flows, earnings and additional investment prospects.

APUC's current quarterly dividend to shareholders is $0.0775 per share or $0.31 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities, reduce short term debt obligations and mitigate the impact of fluctuations in foreign exchange rates. Additional increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "**Board**") and dividend levels shall be reviewed periodically by the Board in the context of available cash 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 produces stable earnings through a diversified portfolio of renewable power and utility businesses owned and operated by its subsidiary entities. APUC conducts its business primarily through two autonomous subsidiaries: APCo, which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; and Liberty Utilities, a diversified rate regulated utility which owns and operates a portfolio of North American electric, natural gas and water distribution utility systems. These businesses of APUC are herein referred to as the "**APUC Businesses**".

APCo – Independent Power Generation

APCo generates and sells electrical energy through a diverse portfolio of renewable power generation and clean thermal power generation facilities across North America. APCo seeks to deliver continuing growth through development of greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of expansion opportunities within APCo's existing portfolio of independent power facilities. APCo's renewable energy division develops and operates APCo's hydroelectric, solar and wind power facilities. APCo's thermal energy division develops and operates co-generation, energy-from-waste, and steam production facilities.

The renewable power and thermal energy generation business of APCo is managed with an emphasis on growth through the development of green-field projects and opportunities within APCo's existing portfolio. This is achieved through APCo's development division which seeks to build on APCo's expertise in the origination of greenfield renewable energy projects, expanding APCo's existing portfolio of renewable and thermal energy assets for further growth, and capitalizing on new opportunities as they arise.

APCo's renewable energy division generates and sells electrical energy through a diverse portfolio of clean, renewable power generation and thermal power generation facilities across North America. APCo owns or has interests in hydroelectric facilities with a combined generating capacity of approximately 170 MW.

APCo also owns or has interests in wind powered generating stations with a combined generating capacity of 650 MW.

Approximately 84% of the electrical output from the hydroelectric and wind generating facilities is sold pursuant to long term power purchase agreements ("**PPAs**") which have a weighted average remaining contract life of 15 years

APCo owns or has interests in thermal energy facilities with approximately 341 MW of installed generating capacity. Approximately 95% of the electrical output from the owned thermal facilities is sold pursuant to long term PPA and which have a weighted average remaining contract life of 7 years. Detailed information on the facilities owned and operated by APCo is set out in Schedules A and B.

Liberty Utilities - Utilities

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

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

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

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems. The regulated natural gas utilities serve approximately 82,050 active natural gas connections located in the States of Missouri, Illinois, and Iowa and the regulated water distribution and wastewater collection utilities serve approximately 11,500 water and wastewater customers located in the States of, Illinois, Missouri, Texas and, as of February 1, 2013, the State of Arkansas.

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

These utilities generally operate under rate regulation, overseen by public utility commissions of the State in which they operate. Detailed information on the water distribution and wastewater, electrical distribution, and natural gas distribution utilities owned and operated by Liberty Utilities are set out in Schedule C, D, and E, respectively.

2.2 Three Year History and Significant Acquisitions

The following is a description of the general development of the business of the Corporation over the last three fiscal years.

(a) **Fiscal 2010**

Corporate

At the annual general meeting on June 23, 2010 (the "**Meeting**"), APUC adopted a Shareholders' Rights Plan (the "**Rights Plan**"). See "*Description of Capital Structure – Shareholders' Rights Plan*".

APCo – Power Generation

(i) **Tinker Facility**

On January 12, 2010, APCo completed the acquisition of three hydroelectric generating stations, a 34.5MW hydroelectric generating facility with sufficient reservoir storage capability to move significant amounts of energy from off-peak to on-peak generation located on the Aroostook River near the Town of Perth-Andover, New Brunswick (the "**Tinker Facility**"), a 0.9MW run-of-river hydroelectric generating facility located in Northern Maine (the "**Caribou Facility**") and a 1.4MW run-of-river hydroelectric generating facility located in Northern Maine (the " **Squa Pan Facility**").

APCo also acquired certain thermal generating facilities in Northern Maine and New Brunswick utilized for installed reserve capacity, not continuous generation, and New Brunswick Public Utilities Board regulated transmission lines and interconnections which allow direct and indirect access to multiple electricity markets (Northern Maine ISA, New Brunswick ISO and ISO-NE).

(ii) **Algonquin Energy Services Inc.**

In connection with the acquisition of the Tinker Facility, on February 4, 2010, APCo acquired an energy marketing company which markets the energy generated from the Tinker Facility. AES is managing this business and it is anticipated that the majority of the energy sold by AES will be supplied through generation from the Tinker Assets, based on historical long term average levels of hydroelectric energy generation of these facilities. AES primarily involves standard offer contracts for the supply of energy to commercial and industrial customers in northern Maine, as well as energy purchase obligations with the ISO-NE required to supplement self-generated energy.

AES' business consists of a series of short-term energy supply agreements. These include energy sales to a town in New Brunswick, standard offer service contracts with three local electric utilities in northern Maine, and a series of direct energy contracts with commercial buyers also in northern Maine.

(iii) **EFW Facility**

A capital upgrade at the EFW Facility was completed in July 2010 and has resulted in higher throughput and lower operating costs per tonne at the Facility in 2011 as compared to periods prior to the upgrade.

Liberty Utilities

(i) **California Utility**

On January 1, 2011, APUC, in partnership with Emera, completed the transaction and acquired the assets comprising an electrical generation and regulated utility (the "**California Utility**") for a gross purchase price of U.S. $136.1 million, subject to certain working capital and other closing adjustments from Sierra Pacific Power Company d/b/a NV Energy and Calpeco dated April 22, 2009. Liberty Utilities acquired 50.001% and Emera acquired 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility assets, Calpeco. On December 21, 2012, APUC acquired the remaining 49.999% ownership in California Pacific Utility Ventures LLC from Emera and as a result, APUC now owns 100% of the California Utility (see Fiscal 2012 highlights).

(ii) **New Hampshire Utility**

On December 9, 2010, APUC announced that Liberty Energy had entered into agreements to acquire all issued and outstanding shares of Granite State Electric Utility, a regulated electric distribution utility, and EnergyNorth Gas Utility, a regulated natural gas distribution utility from National Grid, as outlined in the share purchase agreements by and between National Grid and Liberty Energy entered into on December 8, 2010 and amended and restated on January 11, 2011.

For a more detailed discussion of this acquisition, see " *General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Liberty Utilities – Acquisition of New Hampshire Utility*".

(iii) **Rate Cases**

Liberty Utilities (West) had ongoing rate cases at a number of its utilities which were processed throughout 2010. During the year ended December 31, 2010, Liberty Utilities completed rate case proceedings at nine utilities in Arizona and Texas which on an annualized basis were expected to contribute an additional U.S. $10.2 million in revenue. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. $2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year. One additional rate case requesting U.S. $1.1 million in annual revenue requirement was concluded in the first quarter of 2011.

(iv) **Senior Debt Financing**

The acquisition of the California Utility was funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility entered into on December 29, 2010. The

private placement is a senior unsecured private placement with U.S. institutional investors, and is an obligation solely of the California Utility. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.

On December 22, 2010, Liberty Water completed a private placement financing of senior unsecured 5.6% notes for gross proceeds of approximately U.S. $50 million. The private placement is a senior unsecured private placement with U.S. institutional investors, and is an obligation solely of Liberty Water. The notes have a 10 year term bearing interest until June 2016, at which point annual principal repayments of U.S. $5.0 million will commence. The funds were used to reduce outstanding indebtedness under APCo's senior credit facility ("**APCo Credit Facility**").

(b) **Fiscal 2011**

Corporate

(i) **Issuance of $95.3 million of Common Shares**

On October 27, 2011, APUC completed a public offering (the "**Offering**") of 15,100,000 common shares at a price of $5.65 per share, for gross proceeds of approximately $85.3 million. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued an aggregate of 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

The net proceeds of the Offering were used to fund growth initiatives for both Liberty Utilities and APCo, to partially repay existing indebtedness and for other general corporate purposes.

(ii) **Conversion of Convertible Debentures to Equity**

Effective May 16, 2011 ("**Series 1A Redemption Date**"), APUC redeemed $2.1 million, all of the remaining issued and outstanding principal amount, of Series 1A 7.5% convertible unsecured subordinated debentures due November 30, 2014 (the "**Series 1A Debentures**") and issued 430,666 Common Shares of APUC upon the redemption. Between January 1, 2011 and the Series 1A Redemption Date, $60.339 million principal amount of Series 1A Debentures were converted by debenture holders into 14,788,976 shares of APUC.

(iii) **Strategic Investment Agreement with Emera**

On April 29, 2011, APUC entered into a strategic investment agreement (the "**Strategic Investment Agreement**") with Emera which establishes how APUC and Emera will work together to pursue specific strategic investments of mutual benefit. The Strategic Investment Agreement builds on the strategic partnership effectively established between the two companies in April 2009.

The Strategic Investment Agreement outlines "areas of pursuit" for each of APUC and Emera. For APUC, these include investment opportunities relating to unregulated renewable generation, small electric utilities and gas distribution utilities. For Emera, these include investment opportunities related to regulated renewable generation and transmission projects within its service territories and large electric utilities. APUC is committed to working with Emera on opportunities that fit within APUC's "areas of pursuit".

As an element of the Strategic Investment Agreement, Emera is able to acquire up to 25% of APUC through the purchase of common shares issued by APUC to fund certain investment opportunities under the Strategic Investment Agreement. The Strategic Investment Agreement was approved by shareholders at the annual and special general meeting held on June 21, 2011.

APUC share purchases are made through the acquisition of subscription receipts in exchange for promissory notes at an agreed upon price, which are then exchangeable into common shares upon meeting certain transaction specific conditions, or at a later date at Emera's option, as applicable. The acquisition and conversion of subscription receipts is subject to approvals required under applicable laws, including the rules of the TSX.

APCo – Power Generation

(i) **AES Standard Offer Contract**

In 2011, AES entered into a three year contract with Maine Public Service Company (" **MPS**"), a regulated electric transmission and distribution utility serving approximately 36,000 electricity customer accounts in Northern Maine starting March 1, 2011 to provide standard offer service to multiple commercial and industrial customers in Northern Maine. The anticipated customer load associated with the standard offer service is approximately 135,000 MW-hrs.

(ii) **Windsor Locks Repowering**

The Windsor Locks facility is a 56 MW natural gas powered electrical and steam energy generating station located in Windsor Locks, Connecticut. This facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to Ahlstrom pursuant to an energy services agreement ("**ESA**").

APCo has entered into an agreement to extend the ESA with Ahlstrom from 2017 to 2027. As a result, APCo initiated the process to acquire a new combustion gas turbine which would be more appropriately sized to meet the electrical and steam requirements of the steam host. The new turbine was placed in operation in 2012.

(iii) **APCo Senior Unsecured Debentures**

On July 25, 2011, APCo issued $135 million in senior unsecured debentures (the " **2011 APCo Debentures**") by way of private placement. The net proceeds from the 2011 APCo Debentures were used to repay the outstanding senior project debt financing related to the St. Leon facility (the "**AirSource Senior Debt**") and to reduce amounts outstanding under APCo's senior revolving credit facility. The 2011 APCo Debentures mature on July 25, 2018, and bear interest at a rate of 5.50% per annum, calculated semi-annually payable on January 25 and July 25 each year, commencing on January 25, 2012.

(iv) **APCo Credit Facility Renewal**

On January 14, 2011, APCo received commitments from a syndicate of Canadian banks for a new $142 million credit facility with a three year term. APCo reduced the amount of the APCo Credit Facility to $120 million following the completion of the Senior Unsecured Debenture private placement by APCo in July 2011.

Liberty Utilities

(i) **California Utility**

On April 29, 2011, pursuant to the Strategic Investment Agreement, Emera and APUC agreed to the general terms by which Emera would sell its 49.999% direct ownership in the California Utility to APUC, with closing of such transaction subject to, among other things, execution of a definitive purchase agreement and regulatory approval. On September 12, 2011, Emera US Holdings Inc., a subsidiary of Emera through which it holds its interest in the California Utility, entered into a definitive purchase agreement with Liberty Utilities. In connection with this transaction, Emera entered into a subscription agreement with APUC dated September 12, 2011, pursuant to which Emera subscribed for an aggregate of 8,211,000 subscription receipts from APUC at a price of $4.72 per subscription receipt. Payment for these subscription receipts was satisfied by delivery by Emera of two non-interest bearing promissory notes, one in the amount of $22,608,800 and one in the amount of $16,147,120. The transaction was completed in 2012, as further described below under "*General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Liberty Utilities – Acquisition of Remaining Interest in California Utility*".

(c) Fiscal 2012

Corporate

(i) **Dividend Increased to $0.31 per Common Share Annually**

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

(ii) **Issuance of $120M Preferred Shares**

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

(iii) **Private Placements to Emera**

During fiscal 2012, APUC issued a total of 26,380,750 Common Shares for cash proceeds of $142.6 million pursuant to the conversion of subscription receipts issued to Emera in connection with certain previously announced and completed transactions. The shares were issued in the context of the existing Strategic Investment Agreement which contemplates Emera's investment in APUC of up to 25%.

As at December 31, 2012, Emera owned 34,903,750 Common Shares representing approximately 18.5% of the total outstanding Common Shares of APUC.

Subsequent to December 31, 2012 and pursuant to previously issued subscription receipts or commitments to subscribe for subscription receipts, APUC issued 2,614,005 Common Shares at a price of $5.74 per share, 5,228,011 Common Shares at a price of $5.74 per share and 3,421,000 Common Shares at a price representing $4.72 per share pursuant to conversion of subscription receipts issued to Emera.

On March 26, 2013, Emera subscribed for and purchased 3,960,000 Common Shares of APUC at a price of $7.40 per share for total proceeds of approximately $29 million.

As a result of the transactions after December 31, 2012, Emera owns, as of March 26, 2013, 50,126,766 Common Shares, representing approximately 24.51% of the total outstanding Common Shares of APUC.

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.

(iv) **Conversion of Series 2A Convertible Debentures to Equity**

On February 24, 2012 ("**Series 2A Redemption Date**"), APUC redeemed $57.0 million, representing the remaining issued and outstanding, 6.35% convertible unsecured subordinated debentures due November 30, 2016 ("**Series 2A Debentures**") by issuing and delivering 9,836,520 Common Shares. Between January 1, 2012 and the Series 2A Redemption Date, a principal amount of $2.9 million of Series 2A Debentures were converted by the holders of such debentures into 485,998 common shares of APUC.

(v) **Conversion and Redemption of Series 3 Convertible Debentures to Equity**

On December 31, 2012, holders of $55.3 million of principal amount of 7.0% convertible unsecured debentures due June 30, 2017 (the " **Series 3 Debentures**") converted their debentures into 13,172,619 Common Shares of APUC. On January 1, 2013 (the " **Series 3 Redemption Date**"), APUC completed a redemption of the outstanding Series 3 Debentures by issuing and delivering 150,816 APUC common shares for the remaining $0.9 million in Series 3 Debentures.

(vi) **APUC Credit Facility**

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

Liberty Utilities

(i) **Agreement to Acquire Georgia Utility**

On August 8, 2012, Liberty Utilities entered into an agreement with Atmos to acquire certain regulated natural gas distribution utility systems comprising of the Georgia Utility serving

approximately 64,000 connections located in the State of Georgia. The total purchase price for the Georgia Utility is approximately U.S. $140.7 million representing a 1.1x premium to net assets for regulatory purposes of U.S. $128.1 million and is subject to certain working capital and other closing adjustments.

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

(ii) **Acquisition of Remaining Interest in the California Utility**

On December 21, 2012, a subsidiary of APUC completed the acquisition of the remaining 49.999% ownership in California Pacific Utility Ventures LLC, which owns 100% of the California Utility assets. The subsidiary of APUC acquired the remaining 49.999% interest from Emera through proceeds received from the issuance of 8,211,000 Common Shares of APUC on the conversion of subscription receipts previously issued to Emera. 4,790,000 of such shares which were issued on December 27, 2012, and the remaining 3,421,000 shares were issued on February 14, 2013.

(iii) **Acquisition of New Hampshire Utility**

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

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

(iv) **Acquisition of Missouri Utility**

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

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

(v) **U.S. Debt Private Placements**

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

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

(vi) **Expansion of Liberty Utilities Credit Facility**

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

APCo – Power Generation

(i) **Acquisition of U.S. Wind Facilities**

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

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

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

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

(ii) **APCo $150 million Senior Unsecured Debentures**

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

Net proceeds from the 2012 APCo Debentures were used primarily to fund the investment in the Gamesa Wind Facilities.

(iii) **APCo Credit Facility**

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

(iv) **Completion of Windsor Locks Facility Repowering**

APCo has completed the repowering of the Windsor Locks facility's electrical and steam energy generating station. The installation of a new 14 MW Solar Titan combustion gas turbine was completed in July 2012 at a total capital cost of U.S. $18.3 million (net of one-time non-recurring items: State of Connecticut grant for U.S. $6.5 million; and a U.S. Federal Government heat and power investment tax credit for U.S. $2.4 million) and is now fully operational. As part of the repowering project, APCo had previously entered into an extension of the energy services agreement with Ahlstrom for delivery of 100% of its steam capacity and a portion of its electrical generating capacity. The agreement now continues until 2027. With the new turbine operational, the existing Frame 6 is now available as a peaking turbine to generate additional revenues.

2.3 Recent Developments – 2013

Corporate

(i) **Agreement with St. Leon Class B unit holders**

The St. Leon Facility is a 104 MW wind power generating facility which is owned by St. Leon LP. St. Leon LP had issued an aggregate of 100 Class B units, of which 18 units had been issued to each of Ian Robertson, currently the Chief Executive Officer of APUC and Chris Jarratt, currently the Vice Chair of APUC (the "**Senior Executives**") and an aggregate of 64 units to third parties. APUC and the Class B unit holders (including the partnership owned by the Senior Executives) completed a transaction effective January 1, 2013 whereby the Class B units were exchanged for Series C preferred shares of APUC on a one-for-one basis. The characteristics of the Series C preferred shares will provide approximately the same after tax cash to individuals holding such shares as what was estimated to have been expected from the Class B units. The third parties and the partnerships owned by the Senior Executives who formerly held

the Class B units no longer hold Class B units in St Leon LP. The special committee of the Board retained the services of an independent advisor to review the historic financial performance of the St Leon facility, provide a valuation of the Class B units, provide estimation of distributions to Class B unit holders, and to provide advice to APUC in respect thereof.

Liberty Utilities

(i) **Agreement to Acquire New England Utility**

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

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

(ii) **Acquisition of Arkansas Utility**

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

(iii) **U.S. $100 million Acquisition Term Facility**

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

APCo – Power Generation

(i) **Acquisition of Shady Oaks Wind Facility**

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

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

The facility is comprised of 68 Goldwind GW82 1.5MW and 3 Goldwind GW100 2.5MW permanent magnet direct-drive wind turbines; these turbines are well suited for the wind regime, and offer significant technological advantages providing proven reliability, enhanced energy

production efficiency and lower long term maintenance costs. Through an affiliate, Goldwind has assumed all operations, maintenance, and capital repair responsibilities for the Shady Oaks wind facility pursuant to a 20 year fixed price agreement for the turbines and balance of plant facilities.

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

(ii) **Sale of Small U.S. Hydro Facilities**

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

3. DESCRIPTION OF THE BUSINESS

3.1 General Description of the Regulatory Regimes in which the Business Operates.

(a) **Power Generation Regulatory Regimes**

(i) **Canada**

In Canada, the provinces have legislative authority over the supply of energy. The majority of the electrical supply within the Canadian provinces is provided by large Crown corporations such as Ontario Power Generation Inc. and Hydro-Québec or smaller, investor-owned utilities. These large utilities have been primarily responsible for the generation, transmission and distribution of electricity.

"**Green Power**" is considered electricity generated from renewable energy sources that do not contribute to greenhouse gas emissions. Green Power includes technologies such as small hydroelectric (generally defined as facilities of less than 20 MW in capacity), bioenergy, landfill gas, wind and photovoltaic technologies. Since 1997, both the federal and provincial governments in Canada have provided various incentives to stimulate the production of Green Power in Canada. The incentives have varied from direct subsidies, to tax credits to higher than market rates for electricity generated from renewable energy sources.

The ecoENERGY for Renewable Power is the most recent of a series of incentive programs created by the Canadian Federal government (previous programs were the Wind Power Production Incentive (WPPI) and the Renewable Power Production Incentive (RPPI)) that provides an incentive of one cent per kilowatt hour for up to 10 years to reduce the cost gap between new technologies and traditional sources of electricity. Eligible technologies include electricity generation from renewable energy sources such as wind, low-impact hydro, biomass, photovoltaic and geothermal energy. Although no new contribution agreements were signed after March 31, 2011, signed agreements will continue to receive payments as outlined in contribution agreements and up to March 31, 2021.

(ii) **United States**

The power generation industry in the United States is regulated by the United States Federal Energy Regulatory Commission (" **FERC**") under the U.S. Federal Power Act ("**FPA**") and Public Utilities Regulatory Policies Act (" **PURPA**").

a. Rate Regulation

Certain of APCo's US Facilities are classified as qualifying facilities (" **QFs**"), under PURPA. While QFs were previously exempt from rate regulation under the FPA, due to changes in PURPA, QFs are now subject to rate regulation under Section 205 and 206 of the FPA, subject to certain exceptions. Sales of energy or capacity made by QFs 20 MW or smaller, or made pursuant to a contract executed on or before March 17, 2006, or made pursuant to a state regulatory authority's implementation of PURPA are exempt from regulation under sections 205 and 206 of the FPA. All relevant APCo facilities had PPAs in place predating March 17, 2006, and as such have not been impacted.

The APCo facilities that are not QFs have market-based rate authority under the FPA and thus are subject to less regulation than cost of service based entities.

b. PURPA Regulatory Structure

The purpose of PURPA is to encourage the development of small independent power production. To accomplish this, FERC requires electric utilities to purchase energy and capacity from QFs at the utility's avoided cost. "**Avoided Cost**" means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator.

As a result of the *Energy Policy Act of 2005*, electric utilities are no longer required to purchase energy or capacity from a QF if the utility can prove the QF has non-discriminatory access to:

(1)(i) Independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and

(ii) Wholesale markets for long-term sales of capacity and electric energy; or

(2)(i) Transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords non-discriminatory treatment to all customers; and

(ii) Competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(3) Wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in paragraphs (a)(1) and (a)(2) of this section.

There is a rebuttable presumption that QFs have non-discriminatory access to the market if they are eligible for service under a Commission-approved open access transmission tariff ("**OATT**") and are subject to Commission-approved interconnection rules. There is, however, also a rebuttable presumption that QFs with capacity at or below 20 MWs do not have non-discriminatory access to the market. Because all the APCo QFs have 20 MWs or less of capacity or are on a long term PPA, they qualify for this rebuttable presumption.

(b) **Water Utility Services Regulatory Regimes**

Investor-owned utilities are subject to economic regulation by the public utility commissions of the states in which they operate. The respective public utility commissions typically have jurisdiction over rates, service, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%.

Generally, water and wastewater providers in the United States operate as geographic monopolies within the areas in which they serve. A water or wastewater company is typically provided a service territory defined by a Certificate of Convenience and Necessity which imposes an exclusive right and duty to serve in the service territory. A Certificate of Convenience and Necessity ("**CC&N**") is typically granted by a State agency, which also serves as an economic and service quality regulator for these water or wastewater service providers. Such agencies are charged with ensuring that water and wastewater services are provided at reasonable rates and quality to the company's customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the water or wastewater company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(c) **Electrical Utility Services Regulatory Regimes**

The electricity industry remains perhaps the most highly regulated in the United States. The industry is regulated under strict standards at multiple levels – federal, state and sometimes local. Under the Federal Power Act, FERC regulates interstate transmission, wholesale sales of electricity, corporate acquisitions and dispositions, securities and debt issuances, debt acquisitions, and reliability. State utility commissions perform a similar role, regulating sales of electricity to end-use customers, as well as financial stability and reliability.

Investor-owned electricity utilities are subject to economic regulation by the public utility commissions of the States in which they operate. The respective public utility commissions typically have jurisdiction over rates, services, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a test year in the establishment of rates for the

utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%. This oversight and other rules set by the state utility commissions are intended to ensure reliable service and adequate supplies of electricity together with financial security, transparency in the rate setting process and reasonable prices.

Generally, electricity distribution companies in the United States operate as geographic monopolies within the areas in which they serve. An electricity distribution company is typically provided a CC&N which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these electric service providers. Such agencies are charged with ensuring that electric services are provided at reasonable rates and quality to the company's customers. The agency must balance the interests of the rate payers as well as companies and their shareholders. Rates are approved by the agency to provide the electric services company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(d) **Natural Gas Utility Services Regulatory Regimes**

The natural gas industry is regulated at multiple levels – federal, state and sometimes local. Under the Natural Gas Act, FERC regulates interstate transmission and wholesale sales of gas. Interstate pipeline safety is regulated by the Department of Transportation. State utility commissions regulate retail distribution and sales of natural gas and intrastate pipelines. The federal pipeline safety requirements are often adopted by the state utility commissions and applied to intrastate pipelines and local distribution companies.

Investor-owned natural gas utilities are subject to economic regulation by the public utility commissions of the States in which they operate. The respective public utility commissions typically have jurisdiction over rates, services, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%. This oversight and other rules set by the state utility commissions are intended to ensure reliable service and adequate supplies of natural gas together with financial security, transparency in the rate setting process and reasonable prices.

Generally, natural gas distribution companies in the United States operate as geographic monopolies within the areas in which they serve. A natural gas distribution company is provided a service territory which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these natural gas service providers. Such agencies are charged with ensuring that natural gas services are provided at reasonable rates and quality to the company's customers. The agency must balance the interests of the rate payers as well as companies and their shareholders. Rates are approved by the agency to provide the natural gas utility the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

3.2 Production Method, Principal Markets, Distribution Methods and Material Facilities

(a) **Power Generation: Renewable – Hydroelectric**

(i) **Production Method**

A hydroelectric generating facility consists of a number of components, including a dam, headrace canal or penstock, intake structure, electromechanical equipment consisting of a turbine(s), a generator(s), draft tube and tailrace canal. In addition, there are electrical switchgear and controls equipment which are necessary to interconnect the facility with the receiving electrical grid system.

A dam structure is required to create or increase the natural elevation difference between the upstream reservoir and the downstream tailrace (referred to as "**head**"), as well as to provide sufficient depth within the reservoir for an intake. Dam structures are also used to create an upstream reservoir which allows water to be stored within a head pond.

Water flows are conveyed from the upstream reservoir to the generating equipment via a penstock or headrace canal. A penstock is a pipeline capable of operating under pressure, and is normally constructed of steel or other suitable materials. A headrace canal is a channel which conveys water from the reservoir to the intake in a hydraulically efficient manner. The intake structure is a water intake located at the entrance to a penstock or at the end of a headrace canal. The purpose of the intake structure is to collect water from the upstream reservoir. Turbine(s) and generator(s) transform the hydraulic energy into electrical energy.

The water which has flowed through the hydraulic turbine(s) is discharged back to the natural watercourse. A transmission line is often required to interconnect a facility with the grid. The majority of hydroelectric generating facilities are also equipped with remote monitoring equipment, which allows the facility to be monitored and operated from a remote location.

(ii) **Principal Markets and Distribution Methods**

The principal markets in which APCo operates in Canada are Alberta, Ontario, New Brunswick and Québec. In the US, the principal markets are Maine, New York State and New Hampshire. The majority of generated hydroelectricity is conveyed from the relevant APCo facility to the purchasers under the terms of long term PPAs. The electricity is generally transferred by transmission line from the generating facility to the delivery point for the purchaser, and it is distributed through the grid to end user customers of the purchaser. A summary of the PPAs for APCo's Renewable Energy division is set out in Schedule A.

(1) Alberta

The electrical power industry in Alberta is regulated by the *Electric Utilities Act* (Alberta) (the "**EUA**"). The Power Pool of Alberta (the "**Power Pool**") was established under the EUA to provide a competitive, real-time spot market for electric energy. The Power Pool is non-discriminatory and open to any generator, marketer, distributor, importer or exporter that satisfies the qualification requirements established under the EUA and the rules and codes of practice of the Power Pool.

The EUA has also established the Alberta Electric System Operator (the " **AESO**") to operate and manage the Power Pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy in Alberta. The AESO is governed by an independent board appointed by the Alberta Minister of Energy.

The AESO spot market, or pool price, is determined by market forces. The AESO accepts offers to sell power and bids to buy power through its Energy Trading System. The AESO then dispatches electricity in accordance with an economic merit order based on the lowest cost offers to supply demand in real time. All energy traded through the Power Pool is financially settled each hour at a single spot market price.

Three categories of sellers are eligible to offer and sell electricity through the Power Pool: marketers, importers and independent power producers. There are also three categories of eligible purchasers who may bid to acquire electricity from the Power Pool: retailers, direct access customers and exporters.

(2) Ontario

The Ontario government develops the regulatory framework for wholesale and retail competition through the Ontario Energy Board (the " **OEB**"). While transitional issues such as pricing and metering continue to be considered by the OEB, competition in the wholesale and retail electricity market commenced on May 1, 2002.

The Ontario Electricity Financial Corporation (" **OEFC**") holds all rights, obligations and liabilities under, and purchases the energy generated by the Ontario hydroelectric generating facilities in which APCo has an interest pursuant to, the existing contracts. APCo's subsidiaries have also received a licence to generate from the OEB as required by the *Ontario Energy Board Act*, *1998* (Ontario).

(3) New Brunswick and Northern Maine

In 2003 the New Brunswick government amended the provincial *Electricity Act (New Brunswick)* (the "**Electricity Act**") which resulted in the start of competition in the generation business.

As a result of the Electricity Act, which took effect in October of 2004, New Brunswick Power Corporation (" **NB Power**") was divided into separate businesses. The distribution and customer service division of NB Power now functions as a regulated monopoly and serves all the residential and industrial power consumers in the province, with the exception of those in Saint John, Edmundston and Perth-Andover which are served by Saint John Energy, City of Edmundston Electric and the Perth-Andover Electric Light Commission, respectively.

One of the separate entities created by the Electricity Act is the New Brunswick System Operator (" **NBSO**"), an independent not-for-profit statutory corporation. NBSO is responsible for the adequacy and reliability of the integrated electricity system, and for facilitating the development and operation of the New Brunswick electricity market. These responsibilities take the form of operation of the NBSO-controlled grid and administration of the Open Access Transmission Tariff and the New Brunswick Electricity Market Rules.

The NBSO is the Balancing Authority for New Brunswick, Prince Edward Island, and Northern Maine, and the Transmission Provider for New Brunswick. NBSO provides load following and regulation service to the system in order to supply customer load in the province while

maintaining scheduled flows on interconnections within established limits. NBSO is the authority responsible for the operation of the Bulk Power System in New Brunswick, Nova Scotia, Prince Edward Island, and a portion of northeastern Maine.

(4) Québec

Similar to Ontario, the Québec government develops the regulatory framework for wholesale and retail competition. Since 1991 Hydro-Québec has procured some of its power requirements from private producers on terms and rates negotiated with each producer. The province continues to introduce various programs to stimulate renewable power from hydroelectric and wind powered facilities as well as cogeneration plants fuelled by biomass and natural gas.

In April 2002, the Québec government adopted the *Dam Safety Act (Quebec)* and corresponding regulations. The *Dam Safety Act (Quebec)* imposes a series of safety measures governing the construction, alteration and operation of high-capacity dams. It requires dam owners to maintain their facilities in good repair and monitor their hydraulic works. As a result of this legislation, APCo's Renewable Energy division was required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased by APCo within the Province of Québec.

APCo has spent approximately $1.7 million to date on dam safety evaluations, engineering, permitting and civil works related to the Bill C93 requirements. APCo currently estimates further capital expenditures of approximately $16.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

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

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Mont-Laurier facilities.

- The dam safety evaluation for the Mont Laurier facility was completed in 2008 and APCo's proposed remediation plan has now been accepted by the Quebec government. APCo has been performing engineering and permitting since 2010 and received the Certificate of Authorization from the Quebec government in November 2011. APCo completed the majority of the on-site remediation work in 2012 at a capital cost of approximately $0.3 million. Phase two of the on-site remediation work is scheduled for Q3-Q4 of 2013 at an estimated cost of $0.1 million.
- In respect of the Donnacona facility, APCo completed the dam safety evaluation in 2007 and has been investigating alternative engineering designs to minimize the cost of the remediation work. APCo is now pursuing a design that may result in a cost savings of 20% of the original estimates. APCo completed the engineering for this project in 2012 and submitted a final rehabilitation plan to the Quebec regulators as part of an application for a Certificate of Authorization. The remedial on-site work is anticipated to start in the summer of 2013 and be completed in 2014.

- The dam safety study for the St. Alban facility was completed in 2010 followed by a detailed condition assessment in 2011. APCo anticipates engineering and regulatory review to be completed in 2013, with remedial work performed in 2014 to 2015.
- APCo is presently reviewing options with respect to the Belleterre facility including the removal of several small dams that are not required for power generation. APCo has been corresponding with the Quebec government and other stakeholders about these options since 2007. APCo anticipates completion of any required work on these dams by 2015.
- Engineering for the Riviere-du-Loup facility was completed in fourth quarter of 2012. Following a geotechnical investigation the remediation work is now estimated at $1.1 million.
- The dam remediation work related to Chute Ford was completed in 2012 while the work related to the St. Raphael facility is anticipated to be completed in 2013.

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

(iii) **Material Facilities**

(1) Long Sault Rapids Facility

The Long Sault Rapids facility is an 18 MW hydroelectric generating facility located on the Abitibi River, 19 kilometres north of the Town of Cochrane, in northern Ontario. The Facility was commissioned on April 1, 1998.

The Long Sault Rapids facility was developed by a joint venture between Algonquin Power (Long Sault) Partnership and N-R Power Partnership. The facility is owned by the co-owning joint venturers (the "**Co-Owners**") as tenants-in-common and not as joint tenants, with the co-owners each having an undivided 50% interest in the facility. The partners in the Algonquin Power (Long Sault) Partnership, Algonquin Power (Long Sault) Corporation Inc. and Energy Acquisition (Long Sault) Ltd., are wholly-owned subsidiaries of Algonquin Power Corporation Inc. ("**APC**"), a corporation affiliated with APMI. The partners in the N-R Power Partnership are Nicholls Holdings Inc. and Radtke Holdings Inc., companies controlled by two independent businessmen. There are two non-recourse loans outstanding which are secured against the facility and the Co-Owners' interest therein (see the subsection "*Credit Agreements*" below).

APCo's interest in the Long Sault Rapids facility was acquired by way of subscribing to two notes from the original developers. The notes receivable have a face value of approximately $17 million and bear interest at 9%. APCo earns interest income on the notes and is entitled to 100% of any incremental after tax cash flows from the facility up to 2013, 65% of any incremental after tax cash flows from 2014 to 2027 and 58% of any incremental after tax cash flows thereafter. APCo also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038.

The Long Sault Rapids facility is a "**run of the river**" facility, which means there is a continuous discharge of water from the facility with no storage and release of water. The powerhouse is an integrated structure, housing four 4,500 kilowatt pit turbine generating units.

PPA

Pursuant to the terms of the PPA, the Co-Owners sell power produced by the Long Sault Rapids facility exclusively to OEFC. The PPA terminates 50 years from the commercial in-service date, April 1, 1998, and may be renewed for a further term upon request by either party on terms and conditions to be mutually agreed. The rates are escalated annually based on an index figure tied to OEFC's Total Market Cost index (a minimum of 1% to a maximum of 8%).

The Co-Owners receive a monthly capacity payment when the Long Sault Rapids facility delivers an average of at least 1,800 kilowatts of power delivered to the delivery point in each fifteen minute interval to OEFC during at least 85% or more of the On-peak period fifteen minute intervals for that month. The "**On-peak**" period is between 7:00 a.m. and 11:00 p.m., local time, Monday to Friday, inclusive, but excluding public holidays, and "**Off-peak**" is the other remaining hours. Monthly energy in excess of 115% of target generation is subject to an additional payment.

Waterpower Lease

The waterpower lease with the Province of Ontario in respect of the dam site expires in 2048. The lease provides for an annual land rental and an annual water rental charge. The annual water rental charge commenced in January 2008.

Co-Owners Agreement and Management Agreement

The Co-Owners have entered into an agreement concerning, among other things, their holding of undivided interests in the Long Sault Rapids facility. Upon the occurrence of specified events of default, the non-defaulting Co-Owner may purchase the defaulting Co-Owner's interest for 90% of the fair market value. The Co-Owners have entered into a management agreement with NR-Algonquin Energy Management Inc. to manage the Long Sault Rapids Facility on their behalf for nominal consideration.

Credit Agreements

There is an outstanding senior loan against the Long Sault Rapids facility in the amount of $38.1 million at December 31, 2012. The loan was provided by a syndicate comprised of The Clarica Life Insurance Company ("**Clarica**"), The Canada Life Assurance Company and the Maritime Life Assurance Company. Clarica acts as agent for the syndicate. The loan has a term of 30 years, maturing in January 2028 and bears interest at an interest rate of 10.16% for the first 15 years and 10.21% thereafter, compounded annually. Blended payments of principal and interest are made monthly. The loan is non-recourse to APCo and is secured by the Facility and the ownership interests therein.

Under the terms of the credit agreement, a debt reserve is required. In 2008, APCo issued an irrevocable letter of credit in an amount of $1.2 million to replace the debt service escrow deposit. At December 31, 2012, the debt reserve was fully funded using the irrevocable letter of credit.

APMI Residual Ownership Interest

APCo's interest in the Long Sault Rapids facility is by way of subscribing to two notes from the original developers, which effectively entitles it to 100% of after tax cash flows of the facility up to 2013, 65% from 2014 to 2027 and 58% thereafter. APCo also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038.

An affiliate of APMI is one of the original partners in the Long Sault Rapids facility and is entitled to receive 5% of the equity cash flows commencing in 2014. Subsequent to December 31, 2012, APCo reached an agreement with the affiliate of APMI to acquire residual partnership interest in the Long Sault Rapids hydroelectric facility as part of an agreement to resolve a number of the historic business relationships between APCo and APMI. (See "*Business Associations with APMI and Senior Executives"*).

(2) Côte Ste-Catherine Facility

The Côte Ste-Catherine facility is a hydroelectric generating facility located at the Côte Ste-Catherine lock of the Lachine section of the St. Lawrence Seaway. The bypass canal upon which the facility is located was constructed as part of the St. Lawrence Seaway in 1958. The facility has a total installed capacity of 11.1 MW. The Facility is owned by the Mont-Laurier Partnership.

The land and water rights necessary for the operation of the Côte Ste-Catherine facility have been obtained from the St. Lawrence Seaway Authority by way of a lease agreement with the Province of Québec. In 2009, the water rights lease was renewed for a term of 21 years commencing March 1, 2009. Although the facility is located on a federal waterway, the Province of Quebec has asserted jurisdiction over the water rights to this facility and has also asserted a claim against a predecessor by amalgamation to APFC for payment of revenues paid to the federal authority. See "*Legal Proceedings and Regulatory Actions – Legal Proceedings – Côte Ste-Catherine Water Lease Dues* ".

(3) Mont Laurier Facility

The Mont Laurier facility is a 2.7 MW hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec. The facility is owned by the Mont-Laurier Partnership.

The Facility is constructed on lands owned by the Mont-Laurier Partnership. Water rights necessary for the operation of the facility have been leased from the Ministry of Natural Resources (Québec) pursuant to a lease agreement dated March 23, 1988 and assigned to the Mont Laurier Partnership on October 31, 1994. The term of the lease expires on December 31, 2023.

(4) Côte Ste-Catherine and Mont Laurier PPAs – General

Each of the Côte Ste-Catherine facility and Mont Laurier facility have PPAs with Hydro-Québec under which all power generated by the facilities is sold to Hydro-Québec. The standard Hydro-Québec PPA stipulates annual minimum energy production requirements in each contract year. Under most Hydro-Québec PPAs, if a facility produces less energy than the minimum, a penalty is payable to Hydro-Québec. The facility can opt to reduce any energy production shortfall over a two year period using energy produced in excess of the minimum requirement, after which, a penalty is payable on any outstanding amounts at the current year prices.

Power purchase rates under the Hydro-Québec agreements (other than for the Mont Laurier and Côte Ste-Catherine (Phase I) facilities) increase in accordance with the Consumer Price Index for the Montréal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%. The Mont Laurier facility is subject to a fixed annual escalation of 1.8%. The Côte Ste-Catherine facility (Phase I) power purchase rate increases at a fixed annual index of 1.1% for the first four years and 1.8% thereafter.

(5) Tinker Facility

The Tinker Facility is located 5 miles north of Perth-Andover, New Brunswick and is situated near the mouth of the Aroostook River. The Facility consists of five hydro units and a 1 MW diesel generator; the total nameplate capacity of the station equals 34.5 MW. Unit 5 of the Tinker Facility has been replaced with a new Kaplan variable pitch runner. Gross generation from the upgraded station is expected to be 140,000 MW-hrs per year. The Tinker Facility benefits from the flow regulation of the Squa Pan Facilities, both of which are also owned and operated by APCo.

As part of the generation assets in New Brunswick and Northern Maine, APCo owns and operates an electrical transmission system consisting of 14.7 km of 69 kV transmission line facilities. These facilities are used to interconnect the Tinker Facility to the New Brunswick transmission network, provide transmission service to Perth Andover Electric Light Commission, and provide export/import capacity between Maine and New Brunswick. The transmission facilities are currently included in the Open Access Transmission Tariff of the NBSO.

The Tinker Facility supplies approximately 31,000 MW-hrs per year to the municipal utility of Perth-Andover under a PPA expiring in 2021. The remaining generation from the plant, approximately 109,000 MW-hrs per year, is sold to AES for resale to commercial and industrial customers in the northern Maine and New Brunswick markets, as well as energy and capacity to the Maine and New Brunswick electricity markets.

(6) Dickson Dam Facility

The Dickson Dam Facility is located 20 kilometres west of the Town of Innisfail, Alberta. The Facility is a 15.0 MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the water flows of the Red Deer River. The Dickson Dam Facility consists of three horizontal Francis type turbines and was commissioned into commercial operation on January 16, 1992. The facility is owned by APOT.

APCo sells all of the power generated at the Dickson Dam Facility in the Alberta Power Pool. In addition, APCo has entered into a fixed financial hedge agreement with Capital Power running from May 15, 2012 through December 31, 2016 for variable monthly volumes. The Dickson Dam Facility hedge covers approximately 75% of the expected annual generation volume from the facility.

The Dickson Dam Facility is subject to a Use of Works Agreement with the Government of Alberta under which it has the right to utilize available water flows for generating power until March 31, 2030. The Use of Works Agreement provides certain rights in favour of the Minister of Environment (Alberta) in connection with the Minister’s water management objectives.

(b) **Power Generation: Renewable – Wind Power**

(i) **Production Method**

The energy of the wind can be harnessed for the production of electricity through the use of wind turbines. A wind energy system transforms the kinetic energy of wind into electrical energy that can be delivered to the electricity distribution system for use by energy consumers. When the wind blows, large rotor blades on the wind turbines are rotated, generating energy that is converted to electricity. Most modern wind turbines consist of a rotor mounted on a shaft connected to a speed increasing gear box and high speed generator. Monitoring systems control the angle of and power output from the rotor blades to ensure that the rotor blades are turned to face the wind direction, and generally to monitor the wind turbines installed at a facility.

(ii) **Principal Markets and Distribution Methods**

The principal market for APCo's Canadian wind facilities is Manitoba for the St. Leon, and St. Leon II Facilities, and Saskatchewan for the Red Lily Facility. The electricity generated by the wind turbines is transmitted via electrical collection lines to the facility substations' for subsequent delivery to the transmission system of the purchaser, Manitoba Hydro-Electric Board ("**Manitoba Hydro**") in the case of the St. Leon Facility and St. Leon II, and Saskatchewan Power Corporation ("**SaskPower**") in the case of the Red Lily I facility. The purchaser then distributes the electricity to its customers or to other endpoints via the grid.

In the US, the principal markets are the Regional Transmission Organizations (" **RTO**") of PJM Interconnection (" **PJM**") in the case of the Sandy Ridge, Shady Oaks, and Minonk Facilities and Electric Reliability Council of Texas ("**ERCOT**") in the case of the Senate Wind Facility. Similar to the situation in Canada, the US facilities transmit the wind turbine generated electricity via collection lines to facility substations which are then interconnected to the transmission system for distribution to customers.

(1) Manitoba

Historically, Manitoba Hydro had been exclusively responsible for the production of electricity in the province. Manitoba Hydro is a net exporter of electricity, mainly to Ontario and certain states of the United States. To date, the province has been able to utilize its large hydroelectric resources to satisfy internal and export requirements.

The Manitoba government and Manitoba Hydro have independently undertaken studies to determine the potential of wind power generation in Manitoba. As a result of such studies, the Manitoba Government has advised it plans to have additional capacity of approximately 1,000 MW of wind power, to be constructed, using in part, independent power producers by 2014.

(2) Saskatchewan

Saskatchewan's electricity market remains under provincial government control and has not undergone any significant deregulation. SaskPower, the primary electricity utility in Saskatchewan, is wholly-owned by the province through Crown Investments Corporation. SaskPower anticipates requiring 1,700 MW of additional supply by 2020 and 3,700 MW by 2030

to accommodate load growth and the retirement of generation facilities. As part of this, SaskPower has a number of programs to encourage and solicit wind and other renewable power from independent producers.

(3) Illinois and Pennsylvania

PJM is one of ten RTO's operating in North America. PJM coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Acting as a neutral, independent party, PJM Interconnection operates a competitive wholesale electricity market and manages the high voltage electricity grid to ensure reliability for more than 60 million people.

(4) Texas

ERCOT, like PJM, is one of the ten RTO's operating in North America. ERCOT is the successor to the Texas Interconnect System (TIS) and its region occupies the entire Texas Interconnection which occupies nearly all of the state of Texas. Unlike the other major North American Electric Reliability Corporation interconnections, the high voltage transmission and energy market within the Texas Interconnection is operated by ERCOT as essentially a single power system instead of as a network of cooperating utility companies. The portion of the electric grid in the State of Texas that is under the administration of ERCOT was – and remains – essentially unconnected to electrical grids in other states and, in the absence of "electricity in interstate commerce," does not fall under federal regulation. ERCOT is a membership-based, non-profit council that provides electric power to approximately 23 million people in Texas.

(iii) **Material Facilities**

(1) St. Leon Facility

The St. Leon Facility is a 104 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg. The facility is owned by St. Leon LP.

In January 2010, APCo executed an Operation and Maintenance Service Agreement with Vestas-Canadian Wind Technology, Inc. (" **Vestas**") whereby Vestas provides operation, maintenance and repair services at a contracted rate to the St. Leon Facility for approximately 20 years.

St. Leon LP and St. Leon GP have entered into a PPA with Manitoba Hydro dated as of October 28, 2004 under which all electricity produced at the St. Leon Facility is sold to Manitoba Hydro. As of June 17, 2006, the facility achieved commercial operation status under the PPA with Manitoba Hydro. The term of the PPA is 20 years, with a price renewal term of up to an additional 5 years. Under the terms of the PPA, security in an amount of $1.8 million is required and as at December 31, 2012, the security was fully funded using an irrevocable letter of credit.

St. Leon LP entered into a Wind Power Production Incentive (" **WPPI**") agreement with the Ministry of Natural Resources – Canada which entitles the St. Leon Facility to receive an incentive from the Federal Government of $10.00 per MW-hr to a maximum of $3.7 million annually for a period of ten years ending March 2016. APCo anticipates that the facility will earn WPPI of approximately $3.0 million annually based on the current estimated long term wind resource.

(2) St. Leon II Facility

The St. Leon II Facility is a 16.5 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg, adjacent to the St. Leon Facility.

In July 2011, an affiliate of APCo executed a 25-year PPA with Manitoba Hydro in respect of the St. Leon II Facility. Construction of the St. Leon II Facility was completed in the first quarter of 2012 for a total capital cost of $29.3 million. Beginning July 1, 2012, the facility is generating revenues in accordance with its PPA.

In July 2011, an affiliate of APCo executed an Operation and Maintenance Service Agreement with Vestas whereby Vestas provides operation, maintenance and repair services at a contracted rate to St. Leon II for approximately 20 years.

St. Leon II Wind Energy LP and St. Leon II Wind Energy GP Inc. have entered into an Amended and Restated PPA with Manitoba Hydro dated as of April 4, 2012 under which all electricity produced at the St. Leon II Facility is sold to Manitoba Hydro. As of December 1, 2012, the St. Leon II Facility achieved commercial operation status under the PPA with Manitoba Hydro. The term of the PPA is 25 years, with a renewal term of up to an additional two years, on a season by season basis, at the St. Leon LP's option. Under the terms of the PPA, operational security in an amount of about $300,000 is required through 60 days after the expiry of the term or renewal term, as the case may be. The security was fully funded using an irrevocable letter of credit.

(3) Red Lily Wind Facility

The Red Lily I facility ("**Red Lily I**") is a 26.4 MW wind generation facility located 5 kilometres west of Moosomin, Saskatchewan. Red Lily I consists of 16 Vestas V82 wind turbine generators. The equity in Red Lily I is owned by an independent investor, Concord Pacific Group. Additional senior debt of $31 million has been provided by a third party lender, Integrated Private Debt. As at December 31, 2012, the APCo had a senior debt investment in the facility of $11.6 million that bears interest at the rate of 6.31% per annum and a subordinated debt investment in the facility of $6.6 million that bears interest at the rate of 12.5% per annum. APCo has the option to formally exchange its debt investment and fee interest in the project for a 75% equity interest, exercisable in February 2016. In addition to interest payments on its debt financing, APCo is entitled to certain supervisory fees.

In January 2010, APCo executed an Operation and Maintenance Service Agreement with Vestas whereby Vestas provides operation, maintenance and repair services at a contracted rate to the St. Leon Facility for approximately 20 years.

On July 30, 2008, the owner of Red Lily I entered into a PPA with SaskPower. The PPA term is 25 years from commencement of commercial operation which was February 23, 2011. The PPA also includes a 2% annual increase throughout the term of the agreement.

(4) Shady Oaks Wind Facility

The Shady Oaks wind facility is a 109.5 MW wind energy facility located in the counties of Lee and Brooklyn, Illinois, 80 km west of Chicago. The Shady Oaks wind facility is owned by GSG 6, LLC, an entity acquired by Algonquin Power Co. from Goldwind International SO Limited ("**Goldwind**") on January 1, 2013.

The Shady Oaks wind facility is party to a fixed price Service and Maintenance Agreement with an affiliate of Goldwind, the original equipment manufacturer, whereby the affiliate provides turbine operation, maintenance and repair services at a contracted rate to the Shady Oaks wind facility for the duration of the Warranty Period under the project Turbine Supply Agreement, which is approximately 20 years.

The Shady Oaks wind facility has entered into a 20 year inflation indexed power purchase agreement with the largest electric utility in the state of Illinois, Commonwealth Edison, under which 85% of the electricity produced at the Shady Oaks wind facility and related credits created from the generation of that electricity are sold to Commonwealth Edison. The remaining generation and associated renewable energy credits are sold into the market. The Shady Oaks wind facility reached commercial operation in June 2012. Under the terms of the PPA, security in an amount of US$4.7 million is required. That obligation is being maintained by Goldwind utilizing an irrevocable letter of credit with an associated fee being assessed to Algonquin Power Co.

As at the acquisition date of January 1, 2013, the Shady Oaks wind facility has an outstanding credit facility with the China Development Bank Corporation in the amount of US $150.0 million. The current portions of the facility of U.S. $25.0 million and U.S. $3.0 million are payable on June 30 and November 15, 2013, respectively. The semi-annual principal repayment schedule for the following 11 years ranges from $3.0 million to $6.0 million with a final repayment of U.S. $20 million in 2025. This debt may be repaid in whole or in part at any time without penalty and bears interest at Libor plus 280 basis points.

(5) Sandy Ridge Wind Facility

The Sandy Ridge wind facility is a 50 MW wind energy facility located near Tyrone, PA, 180 km east of Pittsburgh, PA. The Sandy Ridge wind facility is owned by Sandy Ridge Wind, LLC, in which APCo holds an indirect 60% equity interest.

As part of the acquisition of the majority interest in Sandy Ridge Wind, LLC, an Asset Management and Balance of Plant Operations and Service Agreement ("**AMBOSA**") was executed between the facility and Gamesa USA, the operating company for the original equipment manufacturer, in March 2012. Under the AMBOSA the service company provides asset management and balance of plant operations to the owner for a period of 20 years. Asset management services include overseeing an Operations and Maintenance Agreement between the owner and Gamesa Wind US LLC under which turbine operation, maintenance and repair services are provided at a contracted rate to the Sandy Ridge wind facility for a period of 17 years beyond the 3 year warranty period outlined in the facility's Turbine Supply Agreement.

The Sandy Ridge wind facility is party to a long term energy production hedge (" **Energy Production Hedge**") with J.P. Morgan Energy Ventures Corporation ("**JPMVEC**"), the wholly owned subsidiary of J.P. Morgan. The life of the commitment is 10 years. Based on the JPMVEC contract quantity, approximately 72% of energy revenues are expected to be earned under the Energy Production Hedge. All energy produced in excess of that included in the Energy Production Hedge, together with ancillary services including capacity and renewable energy credits, is sold into the energy market in which the Sandy Ridge wind facility is located.

(6) Minonk Wind Facility

The Minonk wind facility is a 200 MW wind energy facility located near Minonk, IL, 200 km southwest of Chicago, IL. The facility is owned by Minonk Wind, LLC, in which APCo holds an indirect 60% equity interest.

As part of the acquisition of the majority interest in Minonk Wind, LLC, an AMBOSA was executed between the facility and Gamesa USA, the operating company for the original equipment manufacturer, in March 2012. Under the AMBOSA the service company provides asset management and balance of plant operations to the owner for a period of 20 years. Asset management services include overseeing an Operations and Maintenance Agreement between the owner and Gamesa Wind US LLC under which turbine operation, maintenance and repair services are provided at a contracted rate to the Minonk wind facility for a period of 17 years beyond the 3 year warranty period outlined in the facility's Turbine Supply Agreement.

The Minonk wind facility is party to an Energy Production Hedge with JPMVEC. The life of the commitment is 10 years. Based on the JPMVEC contract quantity, approximately 73% of energy revenues are expected to be earned under the Energy Production Hedge. All energy produced in excess of that included in the Energy Production Hedge, together with ancillary services including capacity and renewable energy credits, is sold into the energy market in which the facility is located.

(7) Senate Wind Facility

The Senate wind facility is a 150 MW wind energy facility located near Graham, TX, 200 km west of Dallas, TX. The Senate wind facility is owned by Senate Wind, LLC, in which APCo holds an indirect 60% equity interest.

As part of the acquisition of the majority interest in Senate Wind, LLC, an AMBOSA was executed between the facility and Gamesa USA, the operating company for the original equipment manufacturer, in March 2012. Under the AMBOSA the service company provides asset management and balance of plant operations to the owner for a period of 20 years. Asset management services include overseeing an Operations and Maintenance Agreement between the owner and Gamesa Wind US LLC under which turbine operation, maintenance and repair services are provided at a contracted rate to the Senate wind facility for a period of 17 years beyond the 3 year warranty period outlined in the facility's Turbine Supply Agreement.

The Senate wind facility is party to an Energy Production Hedge with JPMVEC. The life of the commitment is 15 years. Based on the JPMVEC contract quantity, approximately 64% of energy revenues are expected to be earned under the Energy Production Hedge. All energy produced in excess of that included in the Energy Production Hedge, together with ancillary services including capacity and renewable energy credits, is sold into the energy market in which the facility is located.

(c) **Power Generation: Thermal – Energy From Waste**

(i) **Production Method**

In North America and elsewhere, the combination of increasing population and stricter environmental regulations has imposed increasing limitations upon the development of new municipal landfills and on the expansion of existing landfills. Energy-from-waste facilities are

considered a viable option to reduce the total tonnage of municipal waste being directed to landfills and to extend the useful life of existing landfills. The establishment of energy-from-waste facilities is now a licensed process in certain states of the United States and Canadian provinces.

The incineration process reduces the waste to an ash which is less than one third of the original volume of waste. The residual ash is then transported to a land fill. The heat recovered from municipal solid waste is used to make steam which can be used to provide thermal energy or can be used to drive turbines and generate electricity.

(ii) **Principal Markets and Distribution Methods**

See the section entitled "*Material Facilities*" immediately below.

(iii) **Material Facilities**

(1) EFW Facility

The EFW Facility is a 10 MW generating station located in Brampton, Ontario which produces electricity from incinerating non-recyclable materials, including municipal solid waste. The facility is designed to incinerate over 500 tonnes per day of municipal solid waste from five incinerators. The EFW Facility generates approximately 60,000 pounds per hour of steam in excess of requirements for production of internally consumed electricity. It is owned by APEFW which forms part of the APCo ownership chain.

In 2012, the EFW Facility received approval from the Ontario Ministry of Environment for an amendment to its environmental permits allowing the EFW facility to accept municipal, industrial, commercial and institutional waste from anywhere in Ontario. In addition the facility is permitted to accept international airport waste from Pearson and Hamilton International Airports. In October 2012, the EFW Facility's contract with the Region of Peel concluded. APCo has now entered into several waste supply agreements with both municipal and commercial entities to ensure continued operation of the facility. In addition, APCo has entered into several agreements to market the EFW capacity in various commercial waste sectors, including specialty wastes and product destruction.

The majority of the EFW steam is diverted to the BCI Facility. See " *Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration – Material Facilities – BCI Facility*". A portion of the EFW Facility steam is used by the EFW Facility to generate electricity in a steam turbine generator, the electricity from which is used to supply internal operations with any excess generation being sold to OEFC.

The EFW Facility is selling electricity at the Hourly Ontario Energy Price (" **HOEP**"). The HOEP is the hourly price that is charged to local distribution companies, other non-dispatchable loads and self-scheduling generators. APCo is currently negotiating with the Ontario Power Authority to enter into a new long term contract for the power output from the EFW Facility.

(d) **Power Generation: Thermal – Cogeneration**

(i) **Production Method**

Cogeneration is the simultaneous production of electricity and thermal energy such as hot water or steam from a single fuel source. Often natural gas is used to produce both electricity and steam. The steam produced is normally required by an associated or nearby commercial facility, while the electricity generated is sold to a utility or used within the facility. Cogeneration provides facilities with greater efficiency, greater reliability and increased process flexibility than conventional generation methods. Examples of industries using cogeneration facilities include food processing, pulp and paper and chemical plants.

Where both electrical and thermal energy are generated separately, typically one third to one half of the fuel's energy content is converted into useful energy output such as steam or electricity. The remainder is wasted energy which escapes as unused heat. By producing electricity and steam simultaneously, cogeneration uses a higher proportion of the fuel's energy content. Depending on the degree of steam and/or useful heat utilization, 55% to 80% of the fuel's energy content is converted into useful energy output, which produces significant fuel savings over conventional arrangements.

Cogeneration compared to conventional processes also has environmental benefits as it results in burning less fuel and producing less carbon dioxide. Furthermore, in cogeneration facilities which use fuels such as natural gas or oil, sulphur dioxide and nitrous oxide emissions are greatly reduced compared to other technologies and fuels.

(ii) **Principal Markets and Distribution Methods**

The principal markets of APCo's cogeneration facilities are California and Connecticut. The electricity produced from these facilities is conveyed from the relevant facility to the electricity markets either under the terms of long-term contracts or according to Independent System Operator rules. In addition, electrical capacity and other ancillary services are sold either under the terms of a long term contract or according to the Independent System Operator rules. A summary of the contracts for the cogeneration facilities is attached in Schedule B. In addition to grid sales of electricity and power, electricity and thermal energy is also sold to nearby third party purchasers for use in their production facilities.

(1) California

The electric transmission system and wholesale markets in California are primarily regulated by the California Energy Commission and FERC. The California Independent System Operator administers the wholesale electricity market place for the region.

(2) Connecticut

Connecticut Light and Power Company (" **CL&P**") is part of the North East Utilities System which is located in the New England Power Pool. The Independent System Operator New England ("**ISO-NE**") was established as a not-for-profit, private corporation on July 1, 1997 following its approval by FERC. The organization immediately assumed responsibility for managing the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff.

Since May 1, 1999, ISO-NE has also administered the wholesale electricity marketplace for the region. Electricity products including energy, capacity and ancillary services are bid, scheduled, bought, and sold by market participants on an internet-based market system.

(iii) **Material Facilities**

(1) Sanger Facility

The Sanger facility is a 56MW natural gas-fired generating facility located in Sanger, California. The Sanger facility is a combined cycle generating station comprised of a 44 MW General Electric LM6000 natural gas fired turbine, commissioned in 2008, and a 12.5 MW Westinghouse steam turbine, originally commissioned in 1991. In 2012, APCo successfully completed a major outage at the Sanger facility that involved an overhaul of the steam turbine, the replacement of the steam turbine generator, and the installation of a new 115kV transformer sized to manage the full output of the facility. The Sanger facility is owned by Algonquin Power Sanger LLC, a subsidiary of APFA.

Output of the Sanger facility is governed by the terms and conditions of a firm capacity and energy PPA with Pacific Gas & Electric Company ("**PG&E**"). The agreement has a term of 30 years, expiring in 2022, and calls for delivery of 38 MW of firm capacity.

Natural gas for the Sanger facility is delivered under the terms of a gas supply agreement dated August 1, 2006 with Constellation NewEnergy for the purchase and sale of all natural gas required for the facility. The expected gas requirement for the subsequent month is bought at the market rates available on the gas nomination date, which is typically the 20th day of each month. Gas above or below the nomination requirement can be bought or sold at the applicable spot prices.

Pursuant to a lease, energy supply and common services agreement with Dyna Fibers Inc., a wholly-owned subsidiary of Sanger LLC, Dyna Fibers Inc. leases a portion of the Sanger facility site in order to carry on its hydro mulch business and purchases certain energy at a cost equal to a percentage of the fuel costs incurred by the facility, to offset the incremental cost of fuel to supply such energy. The water consumption, exhaust heat and steam consumption by the hydro mulch operations are metered and recorded for FERC qualifying facility calculations that are submitted to PG&E on an annual basis.

There is an outstanding senior loan against the Sanger facility in the amount of US $19.2 million as at December 31, 2012. The loan is a California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bond, due September 1, 2020. The senior loan bears interest at variable rates, reset monthly. Interest is payable monthly with no principal repayments. The effective interest rate in 2012 was 2.29%. The loan is secured solely by the Sanger facility, the ownership interests therein and an irrevocable letter of credit in an amount of US $19.5 million.

(2) Windsor Locks Facility

APCo has completed the repowering of the Windsor Locks facility's electrical and steam energy generating station. The installation of a new 14 MW Solar Titan combustion gas turbine was completed in July 2012 at a total capital cost of U.S. $19.3 million (net one-time non-recurring grants from the state of Connecticut and the US Federal Government.) and is now fully operational. As part of the repowering project APCo also entered into an extension of the

energy services agreement with Ahlstrom for delivery of 100% of its steam capacity and a portion of its electrical generating capacity. The agreement now continues until 2027. With the new turbine operational the existing Frame 6 is now available as a peaking turbine to generate additional revenues.

With the repowering complete the Windsor Locks facility has a total installed capacity of 70 MW. The Windsor Locks facility is a combined cycle generating station comprised of a 56 MW General Electric natural gas fired turbine and a 14 MW General Electric steam turbine both commissioned in 1990 and a Solar Titan 130 combustion turbine installed in 2012. The Windsor Locks facility is owned by Algonquin Power Windsor Locks LLC.

The Windsor Locks facility supplies thermal steam energy and the majority of the output from the Solar Titan combustion turbine to Ahlstrom, a leading paper and non-woven materials manufacturer, pursuant to a ground lease and the ESA. Pursuant to the ESA, Ahlstrom leases the facility site to Windsor LLC and utilizes thermal steam energy and a portion of electrical generation of the Facility for use at its specialty fibers composites mill located adjacent to the Facility. APCo has entered into an extension of the ESA with Ahlstrom, the extended term continues until 2027. Payments under the ESA are fully indexed to the cost of natural gas consumed by the Windsor Locks facility.

With the current configuration 90% of the output of the baseload electrical generation is generated by the Solar Titan and is sold to Ahlstrom. The additional installed capacity at the site is committed to the ISO NE market in the day ahead energy market, and the capacity and reserve markets as appropriate. APCo's AES group manages the off-take sales from this Facility into the ISO-NE market.

Natural gas for the Windsor Locks facility is delivered to the facility under gas distribution agreements with Yankee Gas Service Company ("**Yankee Gas**"). APCo's subsidiary, Windsor LLC, has entered into an agreement with a natural gas retailer and wholesale supplier to provide gas to the Windsor Locks facility as required to meet the Ahlstrom ESA obligations and the market dispatch requirements.

(3) BCI Facility

The BCI Facility is a cogeneration facility located in Brampton, Ontario on the EFW Facility site. It was commissioned and became operational in June 2008. The project was established to meet the steam requirements of a nearby recycled paper board manufacturing mill that requires approximately 90,000 pounds of steam per hour in its manufacturing activities.

The BCI Facility consists of a 150,000 pound per hour gas-fired boiler, a water treatment system, pumps to support the boiler, a twelve inch diameter pipeline to supply a nearby recycled paper board manufacturing mill with steam and a six inch diameter pipeline for condensate return. The majority of the steam supplied to the mill is produced by the EFW Facility with the gas-fired auxiliary boiler supporting peak steam demand and providing full standby capacity during normal downtime periods at the EFW Facility and where operations at the EFW Facility cannot provide sufficient volume of steam.

(4) Kirkland Facility

The Kirkland facility is a 132MW combined cycle integrated fuels generation station located in Kirkland Lake, Ontario owned by Kirkland Lake Power Corp. ("**Kirkland**") which burns natural

gas and wood waste to generate electricity using four gas turbines and two steam turbines. The Kirkland facility was developed in two phases: the first 102MW was commissioned in 1991, operating in baseload, and the remaining 30MW was added in 2004 as a dispatchable or peaking plant. Northland Power Inc. ("**Northland**") manages the operations. Electricity produced by the Kirkland facility is sold to OEFC pursuant to a 40 year contract, which expires in 2030. Natural gas used by the Facility is supplied under 20 year supply contracts. Price increases under such gas supply agreements are generally tied to price increases under the PPAs with OEFC. Wood waste consumed by the Kirkland facility is supplied by local forest product companies under contracts of varying terms with the longest being 25 years.

APT owns 32.4% of the Class B non-voting shares issued by Kirkland. It is Kirkland's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Currently, 75% of the operating income of the Facility is paid to Northland under the management agreement.

(5) Cochrane Facility

The Cochrane facility is a 40MW combined cycle integrated fuels generating station located in the Town of Cochrane, Ontario. The Cochrane facility is owned by Cochrane Power Corporation ("**Cochrane**") which burns natural gas and wood waste to generate power using a gas turbine and a steam turbine. The Cochrane facility was commissioned in 1990 and is currently managed by Northland. Electricity produced by the Cochrane facility is sold to OEFC pursuant to a 25 year contract, which expires in 2014. The majority of the natural gas used by the Cochrane facility is supplied under a supply contract which expires in 2016. Price increases under such gas supply agreements are generally tied to price increases under the PPA with OEFC. Wood waste consumed by the facility is supplied by local forest product companies under contracts of varying terms with the longest being 25 years.

APT owns 25% of the Class B non-voting shares issued by Cochrane. It is Cochrane's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Currently, 75% of operating income of the facility is paid to Northland under the management agreement.

(e) **Power Generation: Algonquin Energy Services**

The primary business of AES is to market the output of APCo owned assets which would otherwise sell the energy they generate on a merchant basis. AES also works to develop strategies for selling the power output of APCo facilities that are approaching the end of their PPAs and to engage, where possible, in the negotiation of new contracts that would otherwise sell power on a merchant basis. In addition to traditional wholesale power marketing functions,

AES provides standard offer retail contracts and direct customer retail contracts for the supply of energy to commercial and industrial customers using a series of short-term energy supply agreements.

(i) **Principal Markets and Distribution Methods**

AES provides energy to commercial and industrial customers in Maine and New Brunswick markets. AES purchases energy from the Tinker Facility, based on historical long term average levels of hydroelectric energy generation, the Tinker facility is anticipated to provide greater than 65% of the energy required by AES to service its customers and provides a natural hedge on supply costs of AES.

AES purchases additional energy on the open market to supplement the purchases from the Tinker Facility in order to service its customer demand. AES manages the risk associated with this business through the purchase of fixed volume/prices from the market. In addition, AES negotiates appropriate consumption volumes and pricing indexes with large retail and wholesale consumers in northern Maine to ensure risk associated with volatility of consumption by the consumer is mitigated.

AES is responsible for the strategic management of market exposure for the Gamesa Wind Facilities and Shady Oaks wind facility. These wind facilities, located in the PJM and ERCOT markets, are accompanied by long term hedge or power purchase agreements for a large portion of the projected production; AES develops the strategies for managing the production volumes in excess of the volumes sold under the hedge or power purchase agreements.

(f) **APCo: Development Division**

(i) **Target Markets / Development Strategy**

The Development division works to identify, develop and construct new, renewable and efficient power generating facilities. Development is focused on projects within North America with a commitment to working proactively with all stakeholders, including local communities. It utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains expertise, as required, from the financial, legal, engineering, technical, and construction sectors.

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

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

(ii) **Principal Market Environment**

APCo believes that future opportunities for power generation projects will continue to set targets for renewable and other clean power generation projects.

Within Canada, the Ontario government has reviewed and continues to support the Feed-in-Tariff (" **FIT**") program originally passed under the *Green Energy Act, 2009*. Accordingly the OPA continues to offer standard pricing for electricity from renewable sources. Nova Scotia also continues to offer its Community Feed-in-Tariff ("**ComFIT**") program, albeit on a smaller scale. In July of 2012 Quebec announced the intention to procure up to 700 MW of wind generation through a request for proposals, Saskatchewan recently announced the intention to procure and British Columbia continues to offer its Standard Offer Program ("**SOP**") for renewable projects under 15 MW.

Within the United States, the most notable stimulus for the development of renewable power emanates from the American Recovery and Reinvestment Plan (ARRP) of 2009. The ARRP offers Investment Tax Credits ("**ITCs**") based upon a percentage of eligible capital costs, or Production Tax Credits ("**PTCs**") of $22 per MW hour for wind for the first ten years of production. However additional incentives continue to be offered independently for the development of renewable sources of power at the state and local levels.

APCo will continue to pursue development projects which provide the opportunity to exhibit accretive growth within these markets.

(iii) **Current Development Projects**

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

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

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

(1) Chaplin Wind

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

The project has a targeted commercial operation date of December, 2016. The facility will be constructed at an estimated capital cost of $355 million and consist of approximately 77 multi-megawatt wind turbines. The project is expected to generate first full year EBITDA of $37.5 million. The 25 year PPA features a rate escalation provision of 0.6% throughout the term of the agreement. The project will take advantage of a favourable interconnection location by interconnecting with SaskPower's new P1S 230 kV transmission line from Swift Current to Moose Jaw and will be compliant with SaskPower's latest interconnection requirements.

(2) Amherst Island Wind

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

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

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

(3) Morse Wind Project

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

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

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

(4) Quebec Community Wind Projects

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

Saint-Damase

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

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

Val-Éo

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

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

(5) Cornwall Solar

In the first quarter of 2012, APCo acquired 62.5% of the issued and outstanding shares of Cornwall Solar Inc. (" **Cornwall Solar**"), which owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario (the "**Cornwall Project**"). In addition to the Cornwall Project, APCo has acquired an option to acquire ten additional Ontario based solar projects. APCO has submitted FIT applications for an additional 100MWac.

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

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

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

(iv) **Future Development Projects – Greenfield Projects**

Algonquin continues to pursue new development opportunities as well as build upon an existing portfolio of green-field sites. These projects represent a diversified range of opportunities within hydro, solar, wind and natural-gas modes of generation and are located throughout North America.

(g) **Utilities: Water and Wastewater**

(i) **Method of Providing Services and Distribution Methods**

A utility services company provides regulated utility water supply and/or wastewater collection and treatment services to its customers.

A water utility sources, treats and stores potable water and subsequently distributes it to its customers through a network of buried pipes (distribution mains). A wastewater utility collects wastewater from its customers and transports it through a network of collection pipes, lift stations and manholes to a centralized facility where it is treated, rendering it suitable for discharge to the environment or for reuse, usually as irrigation.

The raw water for human consumption is sourced from the ground and extracted through wells or from surface waters such as lakes or rivers. The water is treated to potable water standards that are specified in Federal and State regulations and which are typically administered and enforced by a State or local agency. Following treatment, the water is either pumped directly into the distribution system or pumped into storage reservoirs from which it is subsequently pumped into the distribution system. This system of wells, pumps, storage vessels and distribution infrastructure is owned and maintained by the private utility.

The fees or rates charged for water are comprised of a fixed charge component plus a variable fee based on the volume of water used. Additional fees are typically chargeable for other services such as establishing a connection, late fee, reconnects, etc.

In respect of sewer or wastewater services, the sewage or wastewater produced by the customer flows through a buried service lateral line from the house or commercial space to the street which line is owned and maintained by the customer. This line feeds into collection pipes or lines (collection mains) located under or adjacent to the street which pipes are owned and maintained by the private utility. These pipes generally slope at a grade of approximately 2% as gravity is generally relied on to facilitate flows. On long line runs where maintaining slopes would result in excessive depths below grade or to traverse variable terrain, the line may terminate at a lift station where wastewater is collected and then pumped up to feed into another line located closer to the surface level where the wastewater can continue to flow by gravity. This is typically referred to as a “force main”.

The wastewater is ultimately delivered to a treatment plant. Primary treatment at the plant consists of the screening out of larger solids, floating material and other foreign objects and, at some facilities, grit removal. These removed materials are hauled to a landfill. Secondary treatment at the plant consists of biological digestion of the organic and other impurities which is performed by beneficial bacteria in an oxygen enriched environment. Excess and spent bacteria are collected from the bottom of the tanks digested and or dewatered and the resulting solids sent to landfill or to land application as a soil amendment. The treated water, referred to as “effluent”, is then used for irrigation or groundwater recharging or is discharged by permit into adjacent surface waters. The standards to which this wastewater is treated are specified in each treatment facilities operating permit and the wastewater is routinely tested to ensure its continuing compliance therewith. The effluent quality standards are based on Federal and State regulations which are administered and continuing compliance therewith enforced by the State agency to which Federal enforcement powers are delegated.

(ii) **Principal Markets**

The principal markets of Liberty Utilities’ water and wastewater plants are located in the United States of America and currently owns utilities operating in the states of Arizona, Texas, Missouri and, as of February 1, 2013, Arkansas. The water and wastewater utilities are generally 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 procedures, issuance of securities, acquisitions and other matters. These utilities generally operate under cost-of-service regulation as administered by these state authorities. The utilities use a historic test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base, recovery of depreciation on plant, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which each utility’s customer rates are determined.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Utilities monitors the rates of return on each of its water and wastewater utility investments to determine the appropriate time to file rate cases in order to ensure it earns the regulatory approved rate of return on its investments. A summary of the rates and tariffs for the wastewater treatment and water distribution business unit is attached in Schedule C.

(1) Arizona

The Arizona Corporate Commission ("**ACC**") is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Arizona. The Arizona Department of Environmental Quality ("**ADEQ**") and the Arizona Department of Water Resources in conjunction with various County agencies (county health units) have primary jurisdiction respecting environmental regulation and compliance.

(2) Texas

The Texas Commission on Environmental Quality (the "**TCEQ**") is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Texas. The TCEQ also has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal *Clean Water Act* and the *Safe Drinking Water Act*, for all water and wastewater treatment service providers, including those owned and operated by municipalities.

(3) Arkansas

The Arkansas Public Service Commission ("**PSC**") is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in Arkansas for rates and charges. The Arkansas Department of Health (ADH) has the regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Clean Water Act and the Safe Drinking Water Act, for all water treatment service providers, including those owned and operated by municipalities. The Arkansas Department of Environmental Quality is the primary regulator for all discharge permits including wastewater treatment utilities in Arkansas.

(iii) **Material Facilities**

(1) Gold Canyon Facility

The Gold Canyon facility is a wastewater treatment facility established in 1984 to serve a number of residential developments and in an unincorporated area of Pinal County referred to as Gold Canyon, approximately 25 miles east of downtown Phoenix, Arizona. The Gold Canyon facility currently serves over 7,500 residential and commercial connections. Gold Canyon facility is owned by a wholly-owned subsidiary in the Liberty Utilities (West) region.

The treatment plant utilizes a biological nutrient removal process combined with a sequencing batch reactor with a treatment capacity of 1.9 million gallons per day ("**gpd**").

The Gold Canyon facility is a consumptive re-use facility and sells its reclaimed A+ effluent for use as irrigation water on two neighbouring golf courses. Excess reclaimed water is recharged (put back into the ground to replenish underground water) via three recharge ponds. The treatment facility operates under ADEQ – Aquifer Protection Permits and Reuse Permits.

(2) Litchfield Park Facility

The Litchfield Park facility is a water distribution and wastewater treatment facility located in the city of Goodyear, 15 miles west of Phoenix, Arizona whose service area includes sections of the cities of Goodyear and Avondale. The Litchfield Park facility is owned by a wholly-owned subsidiary of the Liberty Utilities (West) region.

The Litchfield Park facility presently serves approximately 17,600 water and 19,500 wastewater connections. The wastewater facility has permitted capacity of 4.1 million gpd. The Litchfield Park facility's water infrastructure includes a total of twelve active wells, a 6.3 million gallon reservoir and a 4.0 million gallon reservoir which provides water to the current connection base through a single pressure zone. In 2007, in response to high growth in connections, the Litchfield Park facility began preparing design plans for expansion of its wastewater treatment facility. The capacity expansion was completed at the end of 2012, and final permitting is in process will increase the rated capacity to 5.1MGD from 4.1MGD. The Litchfield Park facility now operates at approximately 70% of design capacity. The Litchfield Park facility supplies Class "A+" effluent to a number of local golf courses in the area.

On February 28, 2013, Liberty Utilities (West) filed a general rate case with the Arizona Corporation Commission related to the Litchfield Park Service Company facilities seeking, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application seeks recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application seeks an accelerated infrastructure recovery surcharge, a Purchased Power Pass through Mechanism to recover power price increases between test years, a Property Tax Accounting Deferral to defer increases in property taxes between test years and a policy statement on rate design to begin the gradual shift of moving more revenue recovery to fixed charges versus commodity charges. The request contemplates a December 31, 2012 test year with new rates are expected to be implemented in the first half of 2014.

The Litchfield Park facility currently has outstanding indebtedness to the City of Goodyear in the amount of U.S. $10.4 million in respect of which the City of Goodyear has acted as a conduit issuer of a like amount of Industrial Development Authority bonds. The bonds consist of two series, both fully amortizing over a 30 year term. The first series was issued in 1999, has a principal amount as of December 31, 2012 of U.S. $3.4 million bearing interest at rates between 5.95%. The second series was issued in 2001 with a principal amount as of December 31, 2012 of U.S. $7.0 million and bearing interest at rates between 6.75%. As partial security for these bonds, the Facility is required to hold funds in a restricted, interest bearing, investment account. The balance of this account at December 31, 2012 was U.S. $1.2 million.

(3) Rio Rico Facility

The Rio Rico facility is a water distribution and wastewater facility located in Santa Cruz County, Arizona approximately 60 miles south of Tucson, Arizona. The Rio Rico facility serves approximately 6,700 water and 2,200 wastewater connections in the community of Rio Rico, Arizona. The Rio Rico facility is owned by a wholly-owned subsidiary of Liberty Utilities (West).

The Rio Rico facility has separate water and wastewater Certificates of Convenience and Necessity and is regulated by the ACC.

On May 31, 2012, Liberty Utilities (West) filed a general rate case with the Arizona Corporation Commission related to the Rio Rico facility seeking, among other things, an increase in EBITDA by U.S. $1.0 million over 2011 results if approved as filed. The application seeks recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application seeks a mechanism that helps mitigate the effects of

regulatory lag on capital investment. The request contemplates a February 29, 2012 test year for its water and wastewater divisions. The next step in the regulatory process is a hearing in March 2013 with new rates expected in Q3 2013.

(4) Pine Bluff Facility

Following the completion of the acquisition on February 1, 2013, Liberty Utilities (Pine Bluff Water) Inc., a subsidiary of Liberty Utilities, is a regulated water utility located in the City of Pine Bluff Arkansas in Jefferson County with approximately 17,000 service connections and serves a population of over 50,000 people. It is regulated by the Arkansas Public Service Commission and has a franchise agreement with the City of Pine Bluff Arkansas.

(h) **Liberty Utilities: Electrical Distribution**

(i) **Method of Providing Services and Distribution Methods**

Electric distribution is the final stage in the delivery system of electricity to end users. An electric distribution system's network carries electricity from the transmission system and delivers it to consumers or other end users. Typically, the network would include medium-voltage (less than 50 kV) power lines, electrical substations, various line apparatus (reclosers, fuses, lightning arrestors), and distribution transformers (pole mounted or pad-mounted), low-voltage (less than 1 kV) secondary distribution wiring and then electric meters used for billing.

An electric distribution utility sources and distributes electricity to its connections through a network of buried or overhead lines. The electricity is sourced from power generation facilities which can use various fuels such as water (hydro), natural gas, coal, bio-mass, wind, nuclear and solar. The electricity is transported from the source(s) of generation at high voltages through transmission lines and is then reduced through transformers to lower voltages at substations. The electricity from the substations is then delivered through distribution lines to the customers where the voltage is again lowered through a transformer for use by the customer.

The rates charged for electric distribution service are comprised of a fixed charge and a variable rate component that recovers the cost of generation, transmission and distribution. Other revenues are comprised of fees for other services such as establishing a connection, late fee, reconnections, and energy efficiency programs, for example.

The electrical distribution utilities located in the Liberty Utilities (West) and Liberty Utilities (East) regions are subject to state regulation and rates charged by these utilities may be reviewed and approved by their respective State regulatory authorities.

(ii) **Principal Markets**

The principal markets are currently in California and New Hampshire where the utilities operate under a cost-of-service methodology. The utilities use a test year in the establishment of its rates and pursuant to this method the determination of the return on approved rate base, recovery of depreciation, together with operating costs, establishes the revenue requirement upon which the utility's customer rates are determined.

Rate cases ensure that a particular utility recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the utility operates. Liberty Utilities monitors the rates of return on its utility investments to

determine the appropriate times to file rate cases in order to ensure it earns the regulatory approved rate of return on its investments. In the case of the California Utility a rate case filing is mandatory every 3 years. A summary of the rates and tariffs for Liberty Utilities' electric distribution utilities is attached in Schedule D.

(1) California

The California Public Utilities Commission ("**CPUC**") regulates investor owned utilities in California and approves the rate of return and the rate base which affects the profitability of the utility.

Energy Cost Adjustment Clause ("**ECAC**") is an annual filing that sets rates to recover the next year's fuel and purchased power costs in addition to setting rates to recover or refund any under/over recovery of previous year's fuel and purchased power costs.

Post Test Year Adjustment Mechanism ("**PTAM**") allows the California Utility to update its rates annually by a cost inflation index. In addition, rates are updated to recover the return on investment and associated depreciation of major capital projects that are placed in service and meet a certain cost threshold.

(2) New Hampshire

The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, water and sewer utilities as defined in RSA 362:2 for issues such as rates, quality of service, finance, accounting, and safety. New Hampshire introduced "retail choice" for customers in 1998. Utility companies are allowed to file distribution rate cases from time to time as the companies determine a need to request adjustments to base rates. There are a number of adjustment factors also in rates, for reliability enhancement programs, vegetation management, energy efficiency and low income support which are reconciled on an annual basis. Electric distribution companies are also required to provide electric commodity service for its customers who do not elect to take service from a competitive supplier. Costs for commodity service are recovered on a direct pass through basis

(iii) **Material Facilities**

(1) California Utility

The California Utility provides electric distribution service to the Lake Tahoe basin and surrounding areas. The service territory, centered around a highly popular tourist destination, has a primarily residential and small commercial customer base spread throughout Alpine, El Dorado, Mono, Nevada, Placer, Plumas and Sierra Counties in northeastern California. The utility plant is comprised of approximately 94 miles of high voltage distribution lines, 13 substations, and 39 distribution circuits (14.4 kV) serving just over 47,000 connections in the seven County service territories. The connection base is heavily-weighted towards El Dorado and Placer Counties, which counties comprise approximately 89% of total revenues.

On December 21, 2012, APUC completed the acquisition of the remaining 49.999% ownership in CPUV, which owns 100% of the California Utility assets. APUC acquired the remaining 49.999% interest from Emera through proceeds received from the issuance of 8,211,000 Common Shares of APUC on the conversion of subscription receipts. 4,790,000 of these shares were issued on December 27, 2012, and the remaining 3,421,000 shares were issued on February 14, 2013.

Connection Base

The California Utility's connection base is primarily residential with large commercial accounts limited to less than 20% of gross revenues. The commercial connections consist primarily of ski resorts, hotels, hospitals, schools and grocery stores with no single connection accounting for more than 3.6% of annual sales volume.

Rate Case

The California Utility's most recent rate case was filed and settled in 2012. The CPUC's decision adopts an all-party settlement for the test year of 2013. The settlement includes a combined increase in both Base Rates and the ECAC of $3.747 million in 2013; a test year rate base of $121.206 million; a 2013 return on equity of 9.875%, based upon a capital structure of 48.5% debt and 51.5% equity, using a long-term debt cost of 5.54% and resulting in an overall rate of return of 7.75%. Rates were implemented on January 1, 2013.

Another element of the decision, a revenue decoupling mechanism and a vegetation management memorandum account was agreed upon. The revenue decoupling mechanism will decouple base revenues from fluctuations caused by weather and economic factors. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses, one of the largest expenses of the utility.

Kings Beach Generation

The California Utility has a local-area emergency backup generation facility at Kings Beach in Placer County, California. The facility consists of six new Caterpillar 3516 Engine diesel generation units with a total nameplate capacity of 12 MW. The units were installed in November 2008 at a cost of U.S. $16.5 million and have an estimated useful life of 30 years. The repowered facility meets all California environmental standards. Any non-preventative maintenance expenditures that may occur during the first five years of operation will be fully covered by the Manufacturer's warranty.

In the event of a system outage, the Kings Beach Facility is able to provide limited back-up generation support to the California Utility's service territory until baseload power is restored. The facility includes quick-start technology which facilitates this support function. The new units are designed to be online and operating within 1 minute of being activated. The facility has historically run an average of 200 hours per year.

Energy Cost Adjustment Clause

ECAC is an annual filing that sets "base rates" to recover the next year's fuel and purchased power costs in addition to setting "amortization rates" to recover or refund any under/over recovery of previous year's fuel and purchased power costs. Rates are effective January 1st of every year.

Post Test Year Adjustment Mechanism

In years where the California Utility does not file a general rate case, its rates are updated on January 1st to reflect inflationary increases to its administrative, operations, and maintenance costs. The inflationary adjustment is set by the use of an index, less a presumed efficiency offset.

The California Utility may also file for an annual increase in rates to recover its investment costs in material capital projects. This increase is subject to a materiality threshold.

PPA

The California Utility entered into a five year all-purpose PPA with NV Energy to provide its full electric requirements at rates NV Energy's "system average cost". The PPA was effective on January 1, 2011 with a five year renewal option. The PPA obligates NV Energy to use commercially reasonable efforts to supply the California Utility with sufficient renewable power to satisfy the current 20% California Renewables Portfolio Standard requirement for the five-year term of the PPA.

NV Energy's deliveries under the PPA are structured in a manner which satisfies the CPUC renewable portfolio standards (" **RPS**") requirements, and the PPA is designed to enable the California Utility to comply with the associated RPS reporting requirements.

Financing

The California Utility entered into a long term debt private placement in an amount of U.S. $70.0 million on December 29, 2010. The private placement is a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate, interest only, and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.

(2) Granite State Electric Utility

Granite State Electric Utility provides distribution service to approximately 43,000 connections in 21 communities located in 2 franchise service areas in southern and northwestern New Hampshire, centered around operating centers in Salem in the south and Lebanon in the northwest. Across approximately 810 square miles of service area, the Corporation's assets consist of 908 miles of overhead distribution lines, 231 miles of underground distribution lines, 15 distribution substations, 37 distribution circuits and 9 sub-transmission circuits.

Connection Base

Granite State Electric Utility's customer base consists of a mixture of residential, commercial and industrial customers with residential customers representing approximately 35,500 of its 43,000 connections. The Corporation's approximate 7,500 commercial and industrial connections are a mix of commercial, retail, medical, education and manufacturing with its largest 10 connections representing approximately 20% of its total annual sales. Its largest customers are a world renowned medical facility and Ivy League educational institution.

Rate Case

In the first half of 2013, Granite State Electric Utility expects to file a rate case with the NHPUC seeking an increase in distribution base rates. The filing is based on a 2012 test year, with revenues and expenses adjusted to reflect known and measurable changes. In addition, Granite State Electric Utility will request approval to implement a "rate year" step adjustment to reflect certain capital additions to rate base after the test year. Among other things, Granite State Electric Utility will also seek to continue current cost-recovery tracking mechanisms, including long-term continuation of the REP/VMP Program and a modification to allow for recovery of pre-staging personnel and equipment for qualifying storms. The case is expected to last one year, with temporary rates expected to be implemented on or about July 1, 2013, permanent rates in or about March 2014, and a step-adjustment sometime thereafter.

Pursuant to a 2007 Settlement Agreement (" **2007 Settlement Agreement**") approved by the NHPUC, Granite State Electric Utility maintains an authorized 50% debt, 50% equity capital structure and a 9.67% authorized return on equity ("**ROE**"). According to the terms of the 2007 Settlement Agreement, Granite State Electric Utility may earn up to 11% before earnings must be shared on a 50-50 basis with customers. Granite State Electric Utility had been earning in excess of its allowed rate of return prior to the 2007 Settlement Agreement. In addition, the 2007 Settlement Agreement provided for a $2.2 million reduction in Granite State Electric Utility's distribution rates reflecting, among other things, an adjustment to offset historical over-earning in two steps: the first step, a $1.1 million reduction, became effective August 2007, and the second step, a $1.1 million reduction, became effective January 2008. The 2007 Settlement Agreement also established a five-year distribution rate plan effective January 1, 2008 through December 31, 2012 (the "**Rate Plan**"), during which distribution rates were frozen except for rate adjustments in the event of certain uncontrollable exogenous events, catastrophic financial events, adjustments to the Storm Fund and moderate annual rate adjustments related to the Corporation's Reliability Enhancement and Vegetation Management Plans Report and Reconciliation ("**REP/VMP**"). The 2007 Settlement Agreement does not prohibit the Corporation from proposing to adjust fees and other charges for new services under its tariff that are subject to Commission approval. Since that time, Granite State Electric Utility has continued to invest in plant as well as its annual investments in the REP/VMP plans. Due in part to the effects of the $2.2 million decrease, the downturn in the US economy, continued investments in the business and rising operating costs, the Corporation's return has suffered in recent years. Therefore, on February 27, 2013 Granite State Electric Utility filed a notice of intent with the NHPUC indicating its plans to file a distribution rate case on March 29, 2013 requesting an increase of $15.2 million in general rates, based on an historic test year of 2012. The requested increase consists of several components; a temporary increase in rates beginning in July 2013, a step increase for investments made in 2013 after the original 2012 test year and the overall rate increase. Under NH law, the NHPUC has one year from the date of filing to make its final ruling on the requested increase.

Default Service Adjustment Provision

Granite State Electric Utility is required to provide electric commodity supply (Default Service) for all customers who do not choose to take supply from a competitive supplier in the New England power market. The competitive market is overseen by the Independent System Operator – New England (ISO-NE). As an electric distribution utility, Granite State Electric Utility is required to participate in the ISO-NE market and abide by its rules under FERC. Granite State Electric Utility is allowed to fully recover its costs for the provision and administration of Default Service under the Default Service Adjustment Provision, as approved by the NHPUC. The Corporation must file with the NHPUC at least twice a year, but may do so more frequently if needed to adjust for market prices of power purchased.

Financing

Granite State Electric Utility currently has outstanding indebtedness in the form of senior unsecured notes consisting of three tranches for an aggregate amount of $15.0 million: U.S. $5 million bearing an interest rate of 7.37%, maturing November 1, 2023; U.S. $5.0 million bearing an interest rate of 7.94%, maturing July 1, 2025; and U.S. $5.0 million bearing an interest rate of 7.30%, maturing June 15, 2028. The notes are interest only and payable semi-annually.

(i) **Liberty Utilities: Natural Gas Distribution**

(i) **Method of Providing Services and Distribution Methods**

Natural gas is a fossil fuel composed almost entirely of methane (a hydrocarbon gas) usually found in deep underground reservoirs formed by porous rock. In making its journey from the wellhead to the customer, natural gas may travel thousands of miles through interstate pipelines owned and operated by pipeline companies.

Because gas flowing from higher to lower pressure is the fundamental principle of the natural gas delivery system, compressor stations may be located every 50-60 miles along the pipelines to boost pressure that is lost through friction. Also along the route, the natural gas may be stored underground in depleted oil and gas wells or other natural geological formations for use during seasonal periods of high demand.

Interstate pipelines interconnect with other pipelines and other utility systems, offer system operators flexibility in moving the gas from point to point. The interstate pipeline companies are regulated by the Federal Energy Regulatory Commission. The gas is transported from various sources at high pressures through transmission lines and is then reduced through gate stations to distribution pressures.

The gas from the gate stations is then delivered through distribution lines to the customer where the gas pressure is again lowered through district regulator stations and/or meter regulators for use by the customer. Typically, the distribution network operates pipelines, gate stations, district regulator stations, peak shaving plants and natural gas meters.

Natural gas reaches Liberty Utilities' natural gas distribution utilities in New Hampshire, Missouri, Iowa, and Illinois through respective city gate stations, where it is measured and injected with an odorant for safety, then distributed to customers through Liberty Utilities' local distribution system of steel and plastic pipelines. The natural gas is sourced from various providers including contracts for natural gas via pipeline as well as liquefied natural gas distributed through its local peak shaving plants.

The gas distribution utilities in Liberty Utilities are subject to state regulation and rates charged by these facilities may be reviewed and altered by the State regulatory authorities from time to time.

(ii) **Principal Markets**

The principal markets are currently in Illinois, Iowa, Missouri and New Hampshire and operate under a cost-of-service regulation. The natural gas utilities use a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base, recovery of depreciation on facilities, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which the utility's customer rates are determined.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Utilities monitors the rates of return on its utility investments to determine the appropriate times to file rate cases in order to ensure it earns the regulatory approved rate of return on its investments. A summary of the rates and tariffs for Liberty Utilities' gas distribution utilities is attached in Schedule E.

(1) New Hampshire

In New Hampshire, EnergyNorth Gas Utility is regulated by the NHPUC. The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, water and sewer utilities as defined in RSA 362:2 for issues such as rates, quality of service, finance, accounting, and safety.

Natural gas bills can be broken down into two primary components, delivery and commodity. The **delivery** charges cover costs associated with the delivery of gas supply through EnergyNorth Gas Utility's pipelines (i.e., gas distribution costs, system maintenance, safety and inspection programs, customer service, metering, billing, etc.) and are regulated by the NHPUC. The rates are based on reasonable and prudent expenses incurred in providing service and a reasonable rate of return on EnergyNorth Gas Utility's plant investment. It is through the allowed rate of return on plant investment that EnergyNorth Gas Utility's has the opportunity to earn a return.

The commodity charge is for gas supply purchased by Energy North on behalf of the customer and is set twice each year (summer and winter periods) with all gas supply costs (i.e., commodity costs, interstate pipeline transportation, underground storage contracts, etc.) factored into the rate. While the interstate pipeline rates are regulated by FERC, natural gas and propane are unregulated commodities. EnergyNorth Gas Utility is allowed to pass these costs onto customers on a dollar for dollar basis, with no mark up. NHPUC Staff conducts regular audits and prudence reviews of all gas supply decisions and related costs. Following a procedural hearing on the issues, the NHPUC sets Cost of Gas Rates.

(2) Illinois

The Illinois operations of Liberty Utilities are regulated by the Illinois Commerce Commission (" **ICC**").

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed Purchased Gas Adjustment.

(3) Iowa

The Iowa operations of Liberty Utilities are regulated by the Iowa Utilities Board (" **IUB**").

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed Purchased Gas Adjustment.

(4) Missouri

The Missouri operations of Liberty Utilities are regulated by the Missouri Public Service Commission (" **MPSC**").

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed Purchased Gas Adjustment.

(iii) **Material Facilities**

(1) EnergyNorth Gas Utility

EnergyNorth Gas Utility is a regulated natural gas utility providing natural gas distribution services to approximately 87,700 connections in 30 communities covering five counties in New Hampshire. Its franchise service area includes the communities of Nashua, Manchester and Concord, NH. EnergyNorth Gas Utility is the largest natural gas distribution utility in the State, with a distribution system consisting of 2,140 miles of distribution pipelines, 2.8 miles of transmission pressure gas pipelines and eight city gate stations, or distribution supply points.

Customer Base

EnergyNorth Gas Utility serves approximately 87,700 connections in New Hampshire with a mix of residential, commercial, industrial and transportation customers. Of its 87,700 connections, approximately 76,400 are residential connections, while 11,300 are commercial and industrial connections. The Commercial and Industrial connection base is a diversified mix of retail, medical, education and industrial uses. No one connection represents more than 3% of its connection base.

Rate Case

EnergyNorth Gas Utility's last rate case was filed on February 26, 2010. As part of a negotiated settlement, the utility was allowed to increase its base rates by $6.8 million utilizing a weighted rate of return of 8.33%. The order was approved on March 10, 2011. The order further provided for a bad debt mechanism, permitting EnergyNorth Gas Utility to recover bad debt subject to limited disallowances, including a potential threshold that would allow it to fully reconcile the commodity portion of its bad debt.

In accordance with the rate case settlement, EnergyNorth Gas Utility agreed to a stay out period for its next distribution rate case filing (subject to certain conditions) for a period of 3 years from the date of the acquisition by Liberty Utilities, or at least 270 days after EnergyNorth Gas Utility had successfully transitioned off at least 70% of the services provided by National Grid under the Transition Service Agreements, whichever occurred sooner.

Energy Cost Adjustment Clause

The cost of gas delivered to customers is recovered when billed to "firm" gas customers through the operation of gas adjustment clauses ("**COG**") included in utility tariffs. The COG provision requires periodic reconciliation of recoverable gas costs and COG revenues.

(2) Midwest Gas Utilities

Midwest Gas Utilities are regulated natural gas utilities providing natural gas distribution services to approximately 83,504 connections in 190 communities in the states of Illinois, Iowa and Missouri. Its franchise service area includes the communities of Virden, Vandalia, Harrisburg and Metropolis in Illinois, Keokuk in Iowa and Butler, Kirksville, Canton, Hannibal, Jackson, Sikeston, Malden and Caruthersville in Missouri. The Midwest Gas Utilities have a distribution system consisting of 2,795 miles of distribution pipelines, 243 miles of transmission pressure gas pipelines and 102 city gate stations, or town border supply points.

Customer Base

Midwest Gas Utilities serve approximately 22,755 connections in Illinois, 4,430 connections in Iowa and 56,319 connections in Missouri with a mix of residential, commercial, industrial and transportation customers. Of its 83,504 connections, approximately 76,816 (92%) are residential connections, while 6,688 (8%) are commercial and industrial connections. The Commercial and Industrial connection base is a diversified mix of retail, medical, education and industrial uses.

Energy Cost Adjustment Clause

The state of Illinois allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). Rate is adjusted monthly with an annual reconciliation based on the calendar year.

The state of Iowa allows full recovery of all gas costs ((including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). Rate is adjusted monthly with an annual reconciliation based on the 12 months ended August of each year.

The state of Missouri allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). Rate is adjusted annually (in November) with allowance to file quarterly. An annual reconciliation is filed based on the 12 months ended August of each year.

3.3 Business Associations with APMI and Senior Executives

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

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

Rattlebrook hydroelectric generating facility

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

Brampton Cogeneration Inc.

BCI is an energy supply facility which sells steam produced from APCo's EFW facility. APMI maintains a carried interest equal to 50% of the annual returns on the project greater than 15%. No amounts have ever been paid under this carried interest. In 2008, APMI earned a construction supervision fee of $0.1 million in relation to the development of this project which has been accrued. This relationship was addressed pursuant to the Agreement.

Long Sault Rapids hydroelectric generating facility

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

Chartered aircraft

APUC utilizes chartered aircraft owned by an affiliate of APMI. At December 31, 2012, the remaining amount of the advance was $nil (December 31, 2011 – $0.3 million).

Office lease

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

Operations services

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

Sanger construction management

As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee. An amount of U.S. $0.6 million has been accrued as an estimate of the final fee owed to APMI. This was settled pursuant to the Agreement.

Clean Power Income Fund

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

Red Lily I

APMI was an early developer of the 26 MW Red Lily I wind power generation facility. As such it is entitled to a royalty fee based on a percentage of operating revenue and a development fee from Red Lily I. This relationship was settled pursuant to the Agreement.

Trafalgar

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

Settlement of Other Business Associations

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

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

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

3.4 Principal Revenue Sources

As at March 31, 2013, APUC owned, directly or indirectly, debt, equity and royalty and other interests in 44 renewable generation facilities and 10 thermal generation facilities including those identified in "*Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments*", two electrical distribution facilities, four natural gas distribution

utilities and 22 water distribution and wastewater facilities. For the year ended December 31, 2012, APUC derived approximately 32.8% of its revenues from its interests in power generation facilities (47.4% in 2011), 3.9% of its revenues from waste disposal fees (6.1% in 2011), 29.3% of its revenues from electrical distribution utilities (28.6% in 2011), 12.6% of its revenues from its interests in water distribution and wastewater utilities (16.6% in 2010), and 20.5% of its revenues from natural gas distribution utilities (nil in 2011).

3.5 Specialized Skill and Knowledge

The senior executives of APUC have extensive contacts in the independent power industry in Canada and the United States.

(i) APCo – Power Generation

APCo's employees, also have extensive experience and contacts in the independent power industry in Canada and the United States. The energy from hydrology aspect of the business of APCo requires specialized knowledge of hydraulic turbines and their various components. This specialized knowledge is available to APCo in-house.

The energy from wind aspect of the business of APCo requires specialized knowledge of wind turbines and their various components. This specialized knowledge is available to APCo in-house. On a more general level, the production of energy from all facilities of APCo requires specialized skill and knowledge, and APCo has employed various personnel who have such skill and knowledge.

AES requires specialized knowledge of the ISO-NE and the energy markets in Northern Maine. APCo has contracted the services of four personnel who previously performed these services for the vendor of the contracts acquired by AES.

(ii) Liberty Utilities

Liberty Utilities requires specialized knowledge of the utility systems served including electrical, gas or water and waste water distribution. Upon acquiring a new utility system Liberty Utilities will typically retain the existing employees with such specialized skill and knowledge.

In addition, Liberty Utilities is adding additional utility trained personnel at its corporate offices to support the expanded portfolio of utility assets.

3.6 Competitive Conditions

APUC competes for projects and acquisitions with individuals, corporations and institutions (both Canadian and foreign) which are seeking or may seek investments similar to those desired by APUC. Availability of investment funds and an increase in interest in these investments may increase competition for them, thereby increasing purchase prices or development costs. Many of these investors have greater financial resources than those of APUC or operate according to more flexible conditions.

(i) APCo – Power Generation

Deregulation has increased demand for privately generated power from a variety of sources including fossil fuels, waste, wind, water, and solar. With deregulation and opening of competition in the electricity marketplace, there should be an increase in the opportunity for the energy customer to choose the type of generation producing the electricity.

The US Department of Energy ("**DEP**") has suggested that in a competitive marketplace, utilities and energy marketers will utilize Green Power pricing to strengthen their image with their customers and build customer loyalty. Further, the DEP has found that most utility customers want their utilities to pursue environmentally benign options for generating electricity and some customers are willing to pay extra to receive power generated by renewable resources. The DEP believes that as deregulation and open competition evolve, the Green Power approach will help offset the relatively higher costs of renewable power compared to less costly gas-fired generation. Additionally, programs and policies are evolving at all government levels, allowing for the trading of greenhouse gas credits created by renewable energy projects to be seen as part of the eventual solution.

Unlike electricity generated by fossil fuels such as natural gas and coal which are subject to potentially dramatic and unexpected price swings due to disruptions in supply or abnormal changes in demand, the supply of hydroelectric, wind and solar power is not subject to commodity fuel price volatility or risk. In addition, the generation of the above forms of power generation do not involve significant ongoing capital and operating costs to ensure strict compliance with environmental regulations, which is a significant advantage over power generated by burning waste or utilizing landfill gases.

Taking into account capital costs, wind and solar power is generally more expensive than traditional forms of generated power, but costs have been decreasing with the increased demand for renewable energy, market competitiveness and improvements in generating technology.

APUC believes that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the United States, continue to increase targets for renewable and other clean power generation projects.

APUC is ideally positioned to take advantage of this demand for increased renewable energy, given that a significant portion of its assets are from renewable sources. It has experience and knowledge in the area. APUC will continue to actively pursue development projects which provide the opportunity to exhibit accretive growth. APUC anticipates its involvement in many future opportunities as initiatives designed to support independent power producers are being supported by virtually every Canadian Province and a significant number of U.S. States.

(ii) **Liberty Utilities**

Liberty Utilities' businesses have geographic monopolies in their service territories and are therefore insulated from competition. Liberty Utilities has developed significant in-house regulatory expertise in order to effectively interact with the state regulators in the various jurisdictions in which it operates. Liberty Utilities believes that the relationship with regulators is unique to each state and therefore is best delivered by local managers who work in the service territory. The local regulatory teams meet with regulatory agencies on regular basis to review regulatory policies, service delivery strategies, operating results and rate making initiatives

3.7 Environmental Protection

The APUC Businesses encompass operations which require adherence to environmental standards imposed by regulatory bodies through licences, permits, standards, policies and legislation. Failure to operate the APUC Businesses in strict compliance with these regulatory standards may expose the APUC Businesses to citations, claims, clean-up costs, penalties, and loss of operating licences and permits.

APUC has an environmental management program including environmental policies and procedures that involve long-term environmental monitoring programs, reporting, government liaison and the development and implementation of emergency action plans as related to environmental matters.

Environmental protection requirements did not have a significant financial or operational effect on APUC's capital expenditures, earnings and competitive position for the twelve months ended December 31, 2012. However it is expected that certain regimes will impact APUC, in terms of increased expenditures, and that these will not affect the competitive position of APUC. Moreover, other regimes that provide incentives and credits for generation of renewable energy and for carbon offsets are expected to increase the earnings and benefit the competitive position of APUC.

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

To manage these risks responsibly, APUC has ensured the environmental and compliance departments have been established within the different subsidiaries which are responsible for monitoring all of each subsidiary's operations, ensuring all operating facilities are in compliance with environmental regulations and preparing regulatory submissions as required.

APUC and its subsidiaries have procedures to prevent and minimize any impact of possible oil spills and soil contamination that meet generally accepted industry practices. APCo's field personnel perform inspections of oil and chemical storage areas on a minimum of a quarterly basis. Liberty Utilities continuously monitor site remediation sites where the company has been named as a potential responsible party and maintain close communication with State representatives. All sites will be remediated in accordance to State approved plans. Each of APUC's businesses have 24 hour, 365 day emergency response and spill procedures in place in the event there is a spill.

3.8 Employees

APUC has 13 employees involved in the management of the corporation. APCo employs a total of 197 employees. With the exception of 39 employees at the EFW Facility and 6 employees at the Tinker Facility, the employees of APCo entities are non-unionized.

Liberty Utilities employs a total of 620 employees. Liberty Utilities employees are non-unionized with the exception of: 58 employees at the California Utility, 47 natural gas utility employees in the Liberty Utilities (Central) region, and 128 employees working for Liberty Utilities (East).

3.9 Foreign Operations

At the current exchange rate, approximately 59% of expected EBITDA in 2012 and 75% of cash flow from operations is generated in U.S. dollars. Currency fluctuations may affect the cash flow that APUC will realize from its operations, as certain APUC Businesses realize revenue and expenses in US dollars.

3.10 Cycles and Seasonality

Power Generation – Hydrology

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

Power Generation – Wind

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

Power Generation – AES

For AES, demand for energy is primarily affected by temperature. Demand for energy during colder months is generally greater than warmer months as the load served by AES is located in a “winter peaking” region.

Liberty Utilities – Water distribution

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.

Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

Liberty Utilities – Electricity distribution

Liberty Utilities (West) region's demand for energy sales are primarily affected by weather conditions. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. Prior to January 1, 2013, Liberty Utilities (West) was exposed to volume sales risk related to seasonal weather variations. Effective on January 1, 2013, pursuant to the CPUC General Rate Case decision, a Base Revenue Requirement Balancing Account ("**BRRBA**")) rate mechanism has been implemented. The BRRBA removes the seasonal variations of revenues and flattens the net revenue (gross revenues less fuel, purchased power, and the ECAC deferral) to a monthly amount of approximately $3.0 million or $35.5 million annually. This mechanism eliminates the risk of revenue variations associated with seasonal weather changes.

Liberty Utilities (East) in New Hampshire experiences peak loads in both the winter and summer seasons, due to heating and cooling loads associated with the New England weather. This phenomenon has been seen across the New England region for some time. The competitive market for power supply is managed by the ISO-NE. Liberty Utilities may see fluctuations in the default service price for power as a result of the weather, but those costs are passed through directly to customers.

Liberty Utilities (East) offers a comprehensive menu of energy efficiency programs in New Hampshire that, in turn, may reduce the demand for energy. Those programs are funded via a charge in distribution rates known as the systems benefit charge, which applies to all utilities. This mechanism provides for an annual reconciliation of costs. If Liberty Utilities is successful in achieving its annual energy efficiency targets, it has the opportunity to earn a performance incentive, which is also recovered via the systems benefit charge.

Liberty Utilities – Natural gas distribution

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

3.11 Customers

The APCo power generation businesses derive their revenues principally from the sale of electricity to large utilities. Liberty Utilities businesses derive their revenues from a diverse residential, commercial and industrial customer base. For the twelve months ended December 31, 2012, APUC Businesses' revenues were derived as follows: Manitoba Hydro – 7.1%; Hydro-Québec – 5.6%; PG&E – 3.4%; electricity sales and distribution – 29.3%; water distribution and wastewater treatment facilities – 2.6%; natural gas sales and distribution – 20.5%; waste disposal fees – 3.9%; and others – 11.7%.

3.12 Economic Dependence

The largest customer on a percentage basis is Manitoba Hydro which totalled 7.1% of gross revenues in the year ended December 31, 2012. This customer maintains an AA S&P rating and receivables are invoiced monthly and generally collected within 20 days.

Similarly, the second largest customer on a percentage basis is Hydro-Québec which totalled 5.6% of gross revenues in the year ended December 31, 2012. This customer maintains an A+ S&P rating and receivables are invoiced monthly and generally collected within 30 days.

Otherwise, APUC does not believe it is substantially dependant on any single contractual agreement or set of related agreements either for the sale of a major part of its products and services or for the purchase of a major part of its requirements for goods, services or raw materials or any franchise or licence or other agreement to use a patent formula, trade secret, process or trade-name upon which its business depends.

3.13 Social or Environmental Policies

The APUC Businesses have safety and environmental compliance policies in place. These policies have been communicated with staff, and have been incorporated into their respective Safety Mission Statements and Employee manuals.

APUC has an Environmental, Health and Safety Group that reports independently to the President of the appropriate region. This group is responsible for developing environmental and safety policies, developing and delivering environmental and safety training, conducting internal audits of environmental and safety performance, and arranging for third party environmental and safety audits.

APUC is actively involved in Corporate Social Responsibility ("**CSR**"). Using the Global Reporting Initiative ("**GRI**"), the Corporation plans on formally tracking several GRI indicators during 2013, with plans to publish its first CSR report in 2014. By weaving CSR into decision making the Corporation reduces liability for investors, increases morale of our engaged employees, creates an environmentally cleaner community, and enhances our partnership with all of our stakeholders. CSR is often defined by a company's philosophy to operate in an economically, socially and environmentally sustainable manner, while recognizing the interests of its stakeholders. Examples of APUC's programs addressing the environment include energy efficiency, water usage, habitat impact, greenhouse gas emissions monitoring, waste reduction and spill prevention. The Economic branch of our CSR efforts incorporates local spending, local hiring, and operational efficiency. Our commitment to people is demonstrated through our employee training, organizational development, emergency management, health and safety, diversity, and community involvement. The Corporation believes this philosophy will contribute to a sustainable future for our investors, communities, environment, customers, employees, governments, and business partners

4. RISK FACTORS

The following are certain risk factors relating to the APUC Businesses. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this AIF and the documents incorporated by reference herein.

4.1 Financial Risk Management

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

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

(a) **Foreign currency risk**

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC Businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 59% of EBITDA in 2012 and 75% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $6.3 million ($0.04 per share) on an annual basis.

APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations and may from time to time enter into derivative contracts to hedge the balance of the cash flow exposure. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes.

(b) **Market price risk**

APCo

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

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

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

The December 10, 2012 acquisition of Senate wind facility included a physical hedge which commences on January 1, 2013 for a 15 year period. The physical hedge is structured to hedge

64% of Senate wind facility's production volume against exposure to ERCOT North Zone current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $1.1 million for the year.

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

The January 1, 2013 acquisition of the Shady Oaks wind facility included a power sales contract which commences on January 1, 2013 for a 20 year period. The power sales contract is structured to provide pricing certainty for approximately 85% of the Shady Oaks wind facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in market prices would result in a change in revenue of about $0.5 million for the year.

Liberty Utilities

Liberty Utilities does not have exposure to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

(c) **Credit/Counterparty risk**

APUC and its subsidiaries are subject to credit risk through its trade receivables 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.

APCo

Approximately 82% of APCo renewable energy division's revenue, approximately 78% of APCo thermal energy division's revenue, and over 80% of APCo's total revenue is earned from large utility customers having a credit rating of BBB- or better.

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

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

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

APCo is also exposed to counterparty credit risk related to the financial hedges entered into with respect to certain facilities. These hedges have been entered predominately with large investment grade financial institutions pursuant to ISDA Master Agreements and Credit Support Annexes providing for security to be posted if certain exposure thresholds are met.

APCo continually monitors the credit rating of its major counterparties and the appropriateness of security if any that may be required.

Liberty Utilities

Liberty Utilities is exposed to credit risk with respect to amounts receivable from customers. Over 80% of Liberty's revenue is derived from services provided to residential customers and as a result there is minimal concentration risk to any one given counterpary. Liberty does not deem its counterparty and credit risk to be significant.

In addition to the counterparty risk related to customer sales outlined above, Liberty Utilities utilizes derivative instruments as hedges of certain price risks related to gas supply. As such Liberty is exposed to credit risk related to counterparties to the extent those derivative instruments are in an asset position at a point in time. Liberty manages the risk by entering into these instruments pursuant to ISDA agreements with counterparties having a credit rating of BBB- or better.

(d) **Interest rate risk**

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

- APUC's operating credit facility is subject to a variable interest rate. The APUC Credit Facility has no amounts outstanding as at December 31, 2012. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The APCo Credit Facility had $27.1 million outstanding as at December 31, 2012. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.3 million annually.
- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2012. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.
- The Liberty Credit Facility had $27.4 million outstanding as at December 31, 2012. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.3 million annually.

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

(e) **Liquidity risk**

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

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

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

APUC currently pays a dividend of $0.31 per common share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements and to fund working capital that, in its judgment, ensures APUC's long-term success.

The long term portion of debt totals approximately $770.9 million with no significant maturities until 2015. In the event that APUC was required to replace the credit 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.

(f) **Commodity price risk**

APCo

APCo's exposure to commodity prices is primarily limited to exposure to natural gas and electricity price risk.

- APCo's Sanger facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in an increase in net revenue by approximately $0.2 million on an annual basis.
- APCo's Windsor Locks facility's ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to Ahlstrom. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.

- APCo's BCI facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in an increase in net revenue by approximately $0.1 million.
- AES provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 250,000 MW-hrs in fiscal 2013. While the Tinker facility is expected to provide a significant portion of the energy required to service these customers, AES anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. In the event that AES was required to purchase all of its energy requirements at ISO-NE spot rates, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $2.5 million on an annualized basis. This risk is mitigated through the use of short-term financial energy hedge contracts. AES has committed to acquire approximately 72,000 MW-hrs of net energy over the next 12 months at an average rate of approximately U.S. $52 per MW-hr.

Liberty Utilities

Liberty Utilities (West)

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

The rate structure in California allows for a pass-through of energy costs to rate payers on a dollar for dollar basis, through the ECAC mechanism, which is designed to recoup power supply costs that are caused by the fluctuations in the price of fuel and purchased power. Actual power supply costs incurred by the facility are tracked and compared to the base rate power supply costs to ensure the cumulative variance, including carrying charges, does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows for an adjustment to the California Utility's approved rates (including carrying charges associated therewith), substantially eliminating the commodity risk associated with the purchase of power.

Liberty Utilities (Central)

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

Liberty Utilities (East)

In the Liberty Utilities (East) region, Granite State Electric Utility 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 Utility provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for residential and small use customers and quarterly for large customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of Granite State Electric Utility's default Service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by Granite State Electric Utility which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC each quarter. Granite State Electric Utility 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.

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

4.2 Operational Risk Management

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

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the generic operational risk of APUC Businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter.

(a) Risks inherent to APUC's businesses

Risk pertaining to Power Generation

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

APCo's existing long term PPAs minimize the risk of reductions in average energy pricing across its portfolio of facilities.

Risks Pertaining to Water Utilities

The water distribution networks of Liberty Utilities operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property. Profitability could be impacted by equipment failure at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards.

These risks are mitigated through the geographic diversification of water distribution operations, and the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. U.S. governmental authorities have the ability to impose restrictions on water usage during drought conditions. If imposed, this could result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

Risks Pertaining to Electric Utilities

The electricity distribution systems owned by Liberty Utilities are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property. These forest fire risks are mitigated through the use of regular vegetation management and line maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. US governmental authorities have the ability to impose restrictions on electricity usage during periods of power generation disruption and loss of adequate transmission capability. If imposed, this could result in decreased demand for electricity, even if supplies are adequate, which could adversely affect revenues and earnings.

Risks Pertaining to Gas Utilities

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

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

(b) **Asset Retirement Obligations**

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations. Based on its assessments, APUC has recorded a liability of $7.1 million in its financial statements which was assumed in 2012 in conjunction with recent acquisitions.

APCo

Generally, APCo's hydroelectric facilities are subject to some form of a water use agreement. The terms of these agreements vary by facility as they are agreements made with the local government body that regulates electrical energy generators and can extend over many years. Certain of the agreements contain clauses which allow the regulating body the option to require APCo to decommission the facility upon the expiry or termination of the agreements. Other facilities have no specific obligations other than to maintain the facility in good working order. APCo has options in many of its existing water use agreements to renew or extend the agreements and anticipates being in a position to extend the majority of its agreements and continue to operate its facilities. Based on historical general practice within the regions in which APCo has facilities, APCo has assessed the probability of being required to decommission a facility upon the expiry of a water use agreement to be remote. As such, any potential asset retirement obligation expense has been assessed as insignificant as the obligation would be incurred well into the future and there is a remote likelihood of being required to decommission a facility.

The owner of the St. Leon Facility does not own the property on which its turbines are located. In 2004, St. Leon entered into long-term right-of-way agreements with land owners which allowed it to construct and maintain the wind turbines used by the facility on their property. These agreements are for minimum terms of 40 years and, upon expiry or termination, provide the land owners with title to the equipment if it is not decommissioned by APCo at its option. While APCo anticipates being in a position to renew or extend the existing PPA in 2025, in the event that APCo is unable to renew or extend the agreement, or identify another purchaser of the energy, APCo may choose to decommission the facility. APCo has assessed there to be a remote likelihood of incurring any cost to decommission the wind farm.

The owner of the Sandy Ridge, Senate and Minonk wind facilities do not own the properties on which the turbines are located but have entered into long-term right-of-way agreements with land owners. These agreements have terms ranging between 30-40 years and, upon expiry or termination, require that all facilities, including foundations below grade be removed. While APCo aims to continue operating these facilities indefinitely, there is a certain probability of being required to decommission a facility upon the expiry of its land lease agreement. As such, APCo recorded an asset retirement liability of $5.7 million as at December 31, 2012.

The owner of the EFW Facility owns the property on which its facility operates. The original Waste Supply Purchase Agreement for the EFW Facility ended in 2012. EFW Facility is currently operating with waste supplied from a number of municipal and commercial customers. As such the EFW Facility is much more reliant on revenue from electricity and steam sales. APCo is also attempting to negotiate a new Power Purchase Agreement with the Ontario Power Authority. While APCo will continue to source waste from the Ontario municipal and commercial sector the Ontario waste sector is extremely competitive. In the event that APCo is unable to successfully obtain waste at economic rates and/or successfully negotiate a PPA with the Ontario Power Authority, APCo may choose to close the facility but has no legal obligation to remove the assets. Should the EFW Facility ever be closed the cost of such closure has been assessed as immaterial.

Liberty Utilities

Water distribution and wastewater collection and treatment utility systems are operated with the assumption that their services will be required in perpetuity and there are no contractual requirements to decommission the entire facility. In order to remain in compliance with the applicable regulatory bodies, Liberty Utilities has regular maintenance programs at each facility to

ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging wastewater treatment facilities and expenses associated with providing new sources of water can generally be included in the facility's rate base and thus Liberty Utilities is allowed to earn a return on its investment.

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

Liberty Utilities operates its natural gas distribution facilities with the assumption that their services will be required in perpetuity and there are no contractual requirements to decommission the entire facility. In order to remain in compliance with the applicable regulatory bodies, Liberty Utilities has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. In addition, the natural gas facilities record asset retirement obligations related to (i) 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, (ii) clean and remove storage tanks containing waste oil and other waste contaminants, and (iii) remove asbestos upon major renovation or demolition of structures and facilities. These maintenance expenses, expenses associated with replacing aging natural gas distribution facilities and expenses associated with providing new sources of electricity can generally be included in the facility's rate base and thus Liberty Utilities is allowed to earn a return on its investment.

(c) **Environmental Risks**

APCo

The APCo Renewable Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a hydroelectric facility include possible dam failure which results in upstream or downstream flooding and equipment failure which result in oil or other lubricants being spilled into the waterway. In addition, the operation of a hydroelectric facility may cause the water in the associated waterway to flow faster, or slower, which could result in water flow issues which impact fish population, water quality and potential increases in soil erosion around a dam facility. In order to monitor and mitigate these risks, APCo completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility. Federal regulators in the U.S. inspect certain hydroelectric facilities on an annual basis and complete an environmental inspection every 3-5 years.

The primary environmental risks associated with the operation of a wind farm include potential harm to the local and migratory bird population, potential harm to the local bat population as well as concerns over noise levels and visual 'harm' to the scenic environment around the wind farm. As part of the federal and provincial approval of the St. Leon wind project, certain pre-construction and post construction monitoring studies were required. No significant issues were identified as a result of these studies. In order to monitor and mitigate these risks, APCo completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility.

The APCo Thermal Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a cogeneration facility include potential air quality and emissions issues, soil contamination resulting from oil spills and issues around the storage and handling of chemicals used in normal operations. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, APCo maintains continuous emissions monitoring systems, performs regular stack testing and tests the calibration of monitoring equipment. The primary environmental risks associated with the operation of an incineration facility include potential air quality, odour and emissions issues, soil contamination resulting from oil or other chemical spills and issues around the storage and handling of municipal solid waste. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, APCo maintains continuous emissions monitoring systems, performs annual stack testing and completes an annual technical evaluation of ash composition.

Liberty Utilities

The primary environmental risks associated with the operation of a wastewater treatment facility include potential air quality and odour management issues, wastewater spills and surface and ground water contamination.

In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Liberty Utilities maintains ongoing sampling and testing programs as required in its operational jurisdiction, including annual field investigations by management. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the wastewater collection system and at the wastewater treatment plants that it operates.

The primary environmental risks associated with the operation of a water distribution facility include risk of groundwater contamination by contaminants such as bacterial, synthetic, organic and inorganic pollutants, consumption and availability of groundwater and ensuring water quality continues to meet and exceed Environmental Protection Agency ("**EPA**") and state standards. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Liberty Utilities maintains a regular sampling and testing program as required in its operational jurisdiction. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the water distribution systems that it operates.

Federal drinking water legislation in the United States requires all drinking water systems to meet specific standards. The costs of complying with drinking water standards form part of a facility's rate case applications.

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

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, Liberty Utilities promptly investigates 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 environmental risks associated with the operation of gas distribution systems are related to uncontrolled natural gas release further to significant leaks, equipment damage by construction equipment/third parties or severe weather events and unauthorized discharges to the environment, respectively. The gas distribution assets are heavily regulated by the Pipeline Hazardous Material Safety Administration ("**PHMSA**") under the United States Department of Transportation and their respective State regulations in which the assets are located. Gas Distribution systems are subject to detailed annual inspections by State Regulatory Agency to ensure strict adherence to applicable regulations. PHMSA reviews company's policies in reference to operation and maintenance, construction, training, emergency response, reporting, contractor management and measurements. Liberty monitors all aspects of pipeline safety and quickly mitigates any identified concerns. Unauthorized gas discharges are reported promptly to the state on discovery, sites are remediated and contaminated soil is disposed in compliance with applicable legislation.

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

Within Liberty Utilities East, one on-going environmental risk is currently being monitored.

The EnergyNorth Gas Utility and Granite State Electric Utility have been named as a potentially responsible party for remediation at 11 sites and 2 sites, respectively, which hazardous waste is alleged to have been disposed as a result of historic operations predating Liberty Utilities' acquisition of the utilities. The EnergyNorth Gas Utility alleged disposal is related to manufactured gas plants ("**MGP**") and related facilities which date back to the late 1800 to early 1950s, Granite State Electric Utility sites are related to alleged disposal of PCB contaminated mineral oil. APUC is currently investigating and remediating, as necessary, those site investigation and remediation ("**SIR**") sites in accordance with plans submitted to the New Hampshire Department of Environmental Services and other agencies. APUC believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position as the clean-up costs are recoverable through rates charged to the customers of the utilities.

Liberty Utilities estimates the remaining cost of these MGP-related environmental cleanup activities will be U.S. $60.2 million, which at a discount rate of 3.5% represents U.S.$56.6 million at December 31, 2012, which has been accrued as Liberty Utilities' estimate of costs for known issues. By rate orders, the regulator provided for the recovery of SIR costs.

(d) **Cycles and Seasonality Risk**

Please see "*Description of the business – Cycles and Seasonality*" for a detailed description and discussion of this risk.

(e) **Specific Environmental Risks**

(i) **APCo – Greenhouse Gas Initiatives**

Several north-eastern U.S. States have formed a coordination group to develop and implement a multi-state greenhouse gas mitigation action plan. This group, the Regional Greenhouse Gas

Initiative ("**RGGI**"), has received backing from states where APCo operates facilities including Connecticut. RGGI drafted a model cap and trade legislation that has been endorsed by all of the states involved in the initiative. The cap and trade program has been implemented to regulate CO_2 emissions from large electrical generation facilities, including the Windsor Locks Facility. The RGGI regulation to implement a greenhouse gas cap and trade program was passed in Connecticut in late August 2008.

The Windsor Locks Facility is the only APCo site that is currently affected by the RGGI regulations. Only the 40 MW gas turbine falls under RGGI as the new 15 MW gas turbine is under the minimum threshold for the RGGI program. As such, APCo only needs to purchase allowances for emissions from the 40 MW turbines which is expected to operate less than 100 hours per year and generate less than 3,000 tons of CO_2 per year. APCo has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks Facility to be between U.S. $6 million and U.S. $12 million.

RGGI has been in effect in Connecticut since 2009. The second compliance period is from January 2012 to December 2014. In 2012, the Facility produced 66,008 tons of CO_2, obtained allowances of 54,298 tons through the UTSA, and had 21,729 surplus tons rolled over from the first compliance period. As a result, no CO_2 allowances were required to be purchased to comply with RGGI. For 2013, it is estimated that the Facility will produce 3,000 tons of CO_2, with 10,019 banked allowances the purchase of allowances is not anticipated. The current price for RGGI allowances is approximately $2.00/ton.

Seven U.S. States (including Arizona and California) and four Canadian provinces (including Manitoba, Ontario and Quebec) have formed a group called the Western Climate Initiative ("**WCI**"). Each member state/province is now responsible for developing the draft design of the Regional Cap-and-Trade Program and taking the necessary steps to implement the Program within its jurisdiction. APCo owns and operates the Sanger Facility in California and the EFW Facility in Ontario and holds investments in two other facilities in Ontario which could be impacted by this program.

On January 2013, the Ontario Ministry of the Environment issued for comments a discussion paper with the key elements of a greenhouse reduction program. This discussion paper kicked off a discussion process with key industry sectors and others stakeholders. The Federal Government is also moving forward with GHG regulations and it is expected that by 2016 a GHG reduction program will be in place. Once a GHG emissions reduction program is in place, APEFW will be required to purchase emissions allocations based on emissions reported, depending on the timing of the implementation of the Provincial program. The EFW Facility submitted the first GHG report under the Ontario Regulation 452/09 in June 2011. The EFW Facility submitted the first GHG report under the Ontario Regulation 452/09 in June 2011. In the future, APEFW will also be required to purchase emissions allocations based on emissions reported for the 2010 and/or subsequent periods, depending on the timing for the implementation of the Provincial Cap-and-Trade program, still under final design and approval.

The State of California is the first member of the WCI to implement a Cap-and-Trade program. This program started on January 1, 2012, with the first enforceable compliance obligation beginning with the 2013 GHG emissions. Under this program, independent power generation facilities are not eligible for direct/free credits allocations, as such, the Sanger Facility will have to make provisions to purchase allowances. In 2012 Algonquin signed an amendment to the Power Purchase Agreement for the Sanger Facility that allows Algonquin to recover all costs for carbon compliance from PG&E through payments for energy. This PPA amendment includes a formula by which PG&E offsets the Sanger Facility's costs of complying with California's cap-and-trade regime for the period of 2013 and 2014. On December 15, 2011, Québec announced the adoption of the cap-and-trade system for

greenhouse gas emission allowances, which is based on the rules established by the WCI. The first year of implementation of the system will be a transition year. It will begin on January 1, 2012 and will allow emitters and participants to familiarize themselves with how the system works. Over the course of the year, emitters will also be able to make any adjustments that may be necessary to meet their obligations under the system for capping and reducing GHG emissions, which will come into force on January 1, 2013.

The Carbon Disclosure Project ("**CDP**") is an independent non-profit organization that represents institutional investors managing over $87.0 trillion in assets. The CDP is specifically working to encourage companies worldwide to quantify and disclose their greenhouse gas emissions and to outline what actions the companies are taking to address climate change risk, both potential physical impacts and regulatory changes that may result in an effort to address climate change.

APCo has submitted an annual greenhouse gas emissions inventory to the CDP since 2008. The inventory is presently being compiled for 2012. The emissions data includes both direct emissions from our processes as well as indirect emissions from purchased power. The emissions inventory has been developed based on guidance from the Greenhouse Gas Protocol. This submission will allow comparisons with other firms to be made, and will also be useful as a baseline for addressing climate change regulations. Results are available on the CDP website.

(ii) **Liberty Utilities (West)**

The Litchfield Park Facility operates where groundwater pollutants, namely trichloroethylene (" **TCE**") originally employed by a former aerospace manufacturing plant in the nearby City of Goodyear, are progressing toward three of the twelve wells that provide water to the Litchfield service area. The EPA began monitoring TCE in 1981 and has been tracking the gradual underground movement since. In addition to actively participating in EPA regular technical meetings in regards to this monitoring program, the Litchfield Park Facility monitors its wells for this groundwater pollutant through the sampling and testing of water from wells that are potentially at risk of contamination.

To date there have not been any detectable levels of TCE in the water from wells used by the Litchfield Park Facility. EPA's monitoring and control efforts have begun to show reducing concentrations in monitoring wells associated with the northeastern portion of the plume, closest to the Litchfield Park Facility wells. Remedial efforts are currently being intensified in the northwestern portion of the plume in order to ensure full capture of the plume. 2011 remedial efforts continue to demonstrate success with a reduction in the threat of contamination at LPSCOs nearest three drinking water wells. The costs of such containment measures are being borne by the "responsible party" (Crane Industries). In the event that any wells exceed the EPA permitted TCE level, the Litchfield Facility would undertake the appropriate actions which may include installing appropriate treatment facilities or removing the well from the water distribution system of the utility. In the event that removal of a well is necessary there would remain sufficient production and reservoir capacity within the balance of the water distribution system to adequately service the needs of all of the Litchfield Park Facility's customers.

In addition, the Litchfield Park Facility has identified alternate sites where replacement wells can be established to replace this potential lost capacity. The cost of establishing a new well is estimated to be between U.S $2.0 million and U.S. $3.5 million depending on the location, depth and other factors. The cost of commissioning a well forms part of the rate base for the utility. Other factors that can impact the cost of a well include, but are not limited to, any requirement to construct wellhead treatment for pollutants, proximity of newly constructed well to water distribution lines, volume of water available at the new site, and acquisition of land and groundwater rights. Liberty Utilities does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.

The Corporation's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2012.

(iii) **Liberty Utilities (East)**

The most active sites currently under the management of Liberty Utilities (East) include the following:

(1) Concord MGP

EnergyNorth Gas Utility received a Notice Letter from the New Hampshire Department of Environmental Services (" **NHDES**") in September 1992. The Notice related primarily to contamination identified in the pond adjacent to Interstate 93 in Concord NH, although it was broad enough to also include the former MGP site itself.

Residual materials from the historic operation of the MGP were discovered in the area of the Exit 13 pond of Interstate 93 as the New Hampshire Dept. of Transportation ("**NHDOT**") began site preparation work for the reconfiguration of that interchange. Subsequent investigations by EnergyNorth Gas Utility and others indicate that contaminants originating from the MGP are present in soil and groundwater between the MGP and the Merrimack River, including within the Exit 13 pond.

The site is currently under Phase III Site remediation, where Phase II was completed and approved by NHDES in July 2012.

(2) Dover MGP

In 1999, NHDES sent notice letters to current and former site owners and operators of the Dover, NH site including Public Service Company of New Hampshire ("**PSNH**") and its parent company, Northeast Utilities (" **NU**"); EnergyNorth Gas Utility; Northern Utilities, Inc.; and Central Vermont Public Service Company ("**CVPS**").

The evaluation of the nature and extent of MGP impacts to the site has been completed. Residual materials from the former MGP have been identified at the site and in the adjacent Cocheco River. These residuals, which include tars, oils, and purifier waste, have been found in surface soil, subsurface soil, groundwater, and river sediment.

The site is currently under the management of PSNH and in Phase IV site remediation. Since 2002, PSNH has had responsibility for site management and conducted most of the work at the site.

(3) Keene MGP

NHDES first investigated a site adjacent to the former Keene MGP in Keene, NH in 1986. PSNH, the former owner and operator, and its parent company NU, conducted several site assessments of the former MGP during the early and mid-1990s. PSNH/NU completed a Site Investigation in 1996 in response to a notice letter from the NHDES. PSNH/NU has had responsibility for site management and interactions with NHDES since that time. In response to

a request from PSNH/NU, NHDES sent a notice letter to EnergyNorth Gas Utility in April 2001. EnergyNorth Gas Utility responded to the NHDES on April 27, 2001, indicating that it would continue to coordinate with PSNH and that it was evaluating its potential liability, if any, at the site.

Residual materials from the former MGP have been identified at the site in sediments of the adjacent Mill Creek and Ashuelot River. Removal of impacted sediment areas constituting readily apparent harm and restoration of the creek bed and portions of the river bed is the likely remedial alternative for the aquatic portion of the site.

The site is currently under the management of PSNH and the seven year remediation project was completed in December 2012. PSNH has taken the lead on investigation at this Site, and the site is under a Phase IV remediation.

(4) Laconia MGP & Liberty Hill Disposal Site

The former MGP was located in Laconia, NH. In the early 1950s, during decommissioning of the MGP, wastes from the MGP were disposed of at a location on Liberty Hill Road in Gilford, NH.

In 1994 and 1995, PSNH one of the former owners and operators of the Laconia MGP, conducted limited site investigations at the plant. In 1996, NHDES sent a “Notification of Site Listing and Request for Site Investigation” for the former Laconia MGP to PSNH and its parent company, NU, and to EnergyNorth Gas Utility, another former owner. EnergyNorth Gas Utility and PSNH reached a settlement in September 1999. As a result of that settlement, PSNH has had responsibility for the MGP site remediation and interactions with NHDES. EnergyNorth Gas Utility retained responsibility for any decommissioning-related liabilities, including off-site disposal (“**Liberty Hill**”).

Residual materials from the former MGP have been identified at the Laconia MGP site and in the adjacent Winnipesaukee River and the site is currently under the lead of PSNH. Residual materials from the former MGP were disposed of at the Liberty Hill Road disposal area, and MGP-related constituents have been detected in soil and ground water.

Based on a settlement with PSNH that has previously been reported to NHPUC, EnergyNorth Gas Utility has had no further involvement with the MGP site since the summer of 1999, except with regard to the Liberty Hill disposal area.

Liberty Hill Road site is currently under Phase III remediation. A Conceptual Remedial Design Report has been approved by NHDES in December 2012. Removal of the impacted materials will be carried over two construction seasons, 2014 and 2015.

(5) Manchester MGP Site

In March 2000, NHDES sent out notice letters to all parties it deemed responsible for the sites any un-investigated MGP Sites in the State. EnergyNorth Gas Utility received a “Notification of Site Listing and Request for Site Investigation” for the former Manchester MGP located in NH from NHDES. Investigations conducted in the summer and fall 2000 confirmed the presence of MGP related contaminants.

Residual materials from the former MGP have been identified at the site. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations and in groundwater at the former MGP, as well as in the downgradient Singer Park and river sediment.

Phase III remediation activities are currently underway.

(6) Nashua MGP Site

At the end of 1998, the NHDES sent a “Notification of Site Listing and Request for Site Investigation” for the former Nashua MGP located in NH to the former plant owners/operators – EnergyNorth Gas Utility and PSNH and its parent company, NU.

Residual materials from the former MGP have been identified at the site and in the adjacent Nashua River. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations, in groundwater, and in localized river sediments.

Phase I and Phase II Site Investigations are complete. The site is currently under Phase III site remediation.

(f) **Regimes that Could Impact APUC**

APCo

As a result of certain legislation passed in Québec (Bill C93), APCo has completed the technical assessments of its hydroelectric facility dams, and have put in place a plan to address deficiencies and are actively implementing corrective actions.

The province of Ontario is considering enacting new legislation similar to Bill C93. APCo operates three hydroelectric facilities in Ontario. While it is too early to assess the costs of compliance, it is possible that modifications to certain dam structures may be required in order to be compliant with any new regulations should they come into effect. Any capital costs associated with the anticipated modifications are expected to be significantly lower than the capital costs related to the Québec Facilities, as there are fewer facilities in Ontario and they are of newer construction.

Liberty Utilities (West)

The State of California is considering legislation that will increase the Renewable Portfolio Standards to 33% from the current 20% by the year 2020 which could impact the source of electricity for the California Utility. Any increases in cost of electricity will be passed on the ratepayers through the General Rate Case process.

(i) **Regimes that Could Benefit APUC**

The US Federal government has committed to implementing a US carbon reduction strategy, and has included revenue from a federal carbon cap-and-trade program in future budget projections. Similarly, the Canadian federal and provincial governments have indicated increased support for Canadian participation in an integrated North American climate change program.

APUC believes that with its existing portfolio of renewable energy and high efficiency cogeneration Facilities the Power Generation business unit is ideally situated to benefit from an improved competitive position within the North American power sector.

In addition, the US Federal government is currently debating the implementation of a country-wide Renewable Energy Portfolio Standard. This would increase the market demand for renewable energy and broaden the opportunities for development of renewable energy projects.

In conjunction with the development of cap and trade programs and working to increase the supply of renewable energy, various North American governments are making legislative and regulatory changes to streamline the approvals process for the development of new renewable energy projects.

(g) **Litigation risks and other contingencies**

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

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

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

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

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

(h) **Tax Related Risks**

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 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.

(i) **Tax Risks Associated with the Unit Exchange**

There is a possibility that the Canada Revenue Agency could successfully challenge the tax consequences of the Unit Exchange or prior transactions of the Corporation or that legislation could be enacted or amended resulting in different tax consequences from those contemplated in the Unit Exchange for APUC. While APUC is confident in its position, such a challenge or legislation could potentially and materially affect the availability or amount of the tax attributes or other tax accounts of APUC.

(j) **Obligations to Serve**

APCo

APCo is not subject to obligations to serve.

Liberty Utilities

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

4.3 Regulatory Climate and Permitting Risks

Profitability of APUC Businesses is in part dependant on regulatory climates in the jurisdictions in which it operates.

APCo

In the case of some APCo hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue. The failure to obtain all necessary licences or permits, including renewals thereof or modifications thereto, may adversely affect cash generated from operating activities.

In the United States, FERC issues licences for the construction, operation and maintenance of hydro-electric generating facilities. Hydro facilities are required to be licenced or have valid exemptions from FERC. Failure to maintain such licences, including amendments or modifications thereto, may result in the owner being unable to operate the licenced facility and could adversely affect cash generated from operating activities.

There are two different mechanisms by which APCo's generating facilities sell power. They either sell power to a utility under a PPA, wherein the price is tied to the market or to the Avoided Cost, or they sell power directly into the market at market-based rates. The ability to sell power at Avoided Cost is dependent on the facility maintaining its qualifying facility status ("**QF Status**") while the ability to sell power at market-based rates is contingent upon either maintaining QF Status or market-based rate authority from FERC. Should a facility lose its QF Status or market-based rate authority, it would be required to sell power under a cost-of-service, which is a more regulated methodology.

Liberty Utilities

Liberty Utilities' water distribution and wastewater collection and treatment utility systems, natural gas distribution utility systems and electric distribution utility systems are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on utility operations. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

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

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

4.4 Dependence upon APUC Businesses

APUC is entirely dependent upon the profitable operations and assets of other APUC Businesses in order to acquire funding for future growth acquisitions. Accordingly, dividends to shareholders are dependent upon the ability of each of the APUC Businesses to pay principal and interest on the notes issued by it and to declare and pay dividends.

4.5 Safety Considerations

The operation of the facilities require adherence to safety standards imposed by regulatory bodies. Failure to operate the facilities in strict compliance with these regulatory standards may expose the Facilities to claims and administrative sanctions. To mitigate the risk of administrative sanctions and to minimize safety risks to employees and contractors, APUC works continuously with all employees to ensure the development and implementation of a progressive, proactive safety culture within all operations. APUC has multiple active safety committees operating with each operating unit and has a dedicated staff to ensure that the existing safety program is continuously improving.

4.6 Labour Relations

While labour relations have been stable to date and there have not been any disruptions in operations as a result of labour disputes with employees, the maintenance of a productive and efficient labour environment cannot be assured.

APCo

With the exception of the EFW Facility and the Tinker Facility, employees of APCo and their material subcontractors are non-unionized. The EFW Facility is unionized and a new collective bargaining agreement was renegotiated in 2011 for a term of three years, until April 2014. The Tinker Facility is unionized and a new collective bargaining agreement was renegotiated in January 2011 for a term of five years.

Liberty Utilities (West)

All employees of Liberty Utilities (West) are non-unionized with the exception of 49 employees at the California Utility. The California Utility is unionized and the current collective bargaining agreement with the International Brotherhood of Electrical Workers ("**IBEW**") was renegotiated in August 2011 for a term of three years, until August 2014. The Corporation has good relations with the IBEW union.

Liberty Utilities (Central)

All employees of Liberty Utilities' water and wastewater utilities and their material subcontractors are non-unionized. There is one union contract with the IBEW covering 40 employees at the natural gas distribution utility in Missouri only. All the other 84 employees in Missouri, Iowa, and Illinois are non-union. The current 1 year contract was negotiated by Liberty and expires on June 1, 2013. Internal discussions have begun in preparation for negotiation meetings later with the union. Liberty Utilities has good relations with the IBEW union.

Liberty Utilities (East)

There are four union contracts in New Hampshire. The United Steelworkers represent approximately 88 employees working in field operations in gas. In the electric business there are two International Brotherhood of Electrical Workers locals representing approximately 25 field employees. There are also two engineers in the Utility Workers Union of America. The Steelworker contract was recently re-negotiated and will expire in April 2016. The IBEW contracts will expire in May 2014. The UWUA contract will expire on May 11, 2013 and are expected to be renegotiated without any issues.

4.7 Dependence Upon Key Customers

APCo

The customers of APCo's power generation facilities are primarily large utilities. See the summaries of the contracts in Schedules A and B. If, for any reason, such customers were unable to fulfill their contractual obligations under the PPAs, cash flow available to shareholders of APUC would decline.

Liberty Utilities

The customers of Liberty Utilities are primarily residential. Large commercial and industrial customers make up less than 20% of gross revenues, with no single customer accounting for a significant portion of gross revenues. As such, Liberty Utilities is not dependent upon a few key customers.

4.8 Potential Conflicts of Interest

On December 21, 2009, an agreement was reached to internalize management. Unitholders had previously been dependent on APMI for the administration of APCo and for management and operation of the Facilities. Since December 21, 2009, management of APUC has been conducted by officers of APUC. There may be situations in which conflicts of interest may arise between the Senior Executives of APUC in relation to the interests of APUC. Transactions involving related parties, including the Senior Executives who are principals of APMI, are disclosed in APUC's annual financial statements and management's discussion and analysis as at and for the period ended December 31, 2012.

4.9 Construction / Development Risk

Successful development of wind and other energy projects are subject to significant risks and uncertainties including those relating to the ability to obtain financing on acceptable terms, currency fluctuations affecting the cost of major capital components such as turbines, price escalation for construction labour and other construction inputs, construction risk that the project is built with mechanical defects, is not completed on time and is not within budget estimates.

4.10 Acquisitions and Divestitures

Acquisitions of complementary businesses and technologies are a part of APUC's overall business strategy. In spite of the complementary nature of any businesses or technologies acquired, there is always a risk that services, technologies, key personnel or businesses of acquired companies may not be effectively assimilated into APUC's business or service offerings. Similarly, divestitures of businesses that are no longer viewed as being strategic to APUC's continuing operations can be an active part of APUC's overall business strategy. Divestitures may result in a reduction in total revenues and net income.

APCo and Liberty Utilities each have a transition management office (" **TMO**") that have developed standard project management and governance processes to manage its respective company integrations due to acquisitions. These processes ensure an effective organization of people, resources and time frames for a successful integration of technology, operations, asset management and business processes. The TMO uses a sound governance reporting structure which includes the participation of APCo and Liberty Utilities senior management to ensure that the respective operations and processes are implemented in a timely and efficient manner. The governance process also includes a transparent issue resolution process which is documented and reported throughout APCO and Liberty Utilities.

5. DIVIDENDS

Common Shares

The total amount of dividends declared on APUC common shares for fiscal 2010, 2011 and 2012 were $22.8 million, $32.4 million, and $50.2 million, respectively. The amount of dividends declared for each Common Share of APUC for fiscal 2010, 2011 and 2012 were $0.24, $0.27 and $0.30, respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. Effective August 9, 2012, the Board established a quarterly dividend of $0.0775 or $0.31 annually.

The Board has adopted a dividend policy to provide sustainable dividends to shareholders, considering cash flow from operations, financial condition, financial leverage, working capital requirements and investment opportunities. The Board can modify the dividend policy from time to time in its discretion. There are no restrictions on the dividend policy of APUC. The amount of dividends declared and paid is ultimately dependent on a number of factors, including the risk factors noted above. See "*Risk Factors*".

Preferred Shares

On November 9, 2012 APUC issued 4,800,000 Series A Shares. For an initial six year period the holders of Series A Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the board of directors, payable quarterly on the last business day of March, June, September and December in each year at an annual rate equal to $1.1250 per Series A Share. An initial dividend of $0.1603 per Series A Share was declared, and paid on December 31, 2012.

5.1 Dividend Reinvestment Plan

Effective October 1, 2011, APUC introduced a shareholder dividend reinvestment plan (the " **Reinvestment Plan**") which is offered to registered holders of Common Shares of APUC.

The purpose of the Reinvestment Plan is to enable Shareholders to invest all cash dividends on Common Shares in additional shares of APUC ("**Plan Shares**"). All such Plan Shares will be, at APUC's election, either (i) Common Shares purchased on the open market through the facilities of the TSX ("**Market Purchase**") or (ii) newly issued Common Shares purchased from APUC (" **Treasury Purchase**").

The price at which Plan Shares will be purchased with such cash dividends will be (i) in the case of a Market Purchase, the volume weighted average price paid (excluding brokerage commissions, fees and transaction costs) per Plan Share by the Agent for all Plan Shares purchased in respect of a Dividend Payment Date under the Reinvestment Plan, or (ii) in the case of a Treasury Purchase, the volume weighted average of the trading price for Common Shares on TSX for the five (5) trading days immediately preceding the relevant dividend payment date less a discount, if any, of up to five percent (5%), at APUC's election. No commissions, service charges or brokerage fees are payable by Shareholders in connection with the Reinvestment Plan.

As at March 26, 2013, 28.7 million Common Shares had been registered with the Reinvestment Plan.

6. DESCRIPTION OF CAPITAL STRUCTURE

6.1 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 Common Shares 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 Common Shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

As at December 31, 2012, APUC had 188,763,486 issued and outstanding Common Shares and, as at March 26, 2013, APUC had 204,475,902 issued and outstanding Common Shares.

6.2 Private Placements of Subscription Receipts and Common Shares to Emera

For the year ended December 31, 2012, APUC issued a total of 26,380,750 Common Shares for proceeds of $142.6 million pursuant to the conversion of subscription receipts issued to Emera in contemplation of certain previously announced transactions, as outlined below:

- On May 14, 2012, in connection with the acquisition of Granite State Electric Utility and EnergyNorth Gas Utility, APUC issued 12,000,000 Common Shares at a price of $5.00 per share to Emera pursuant to a subscription receipt agreement. The $60.0 million cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisitions.
- On June 29, 2012, in connection with the acquisition of Sandy Ridge wind facility, APUC received $15.0 million relating to 2,614,006 subscription receipts issued at a price of $5.74 per share and issued the Common Shares related to these subscription receipts on July 13, 2012.

- On July 31, 2012, in connection with the acquisition of the Midwest Gas Utilities, APUC issued 6,976,744 Common Shares upon conversion of the same number of subscription receipts, which were issued to Emera at a price of $6.45 per subscription receipt. The $45.0 million cash proceeds of the subscription receipts were used to fund a portion of the cost of the Midwest Gas Utilities acquisition.
- On December 21, 2012, in connection with the acquisition of Emera's noncontrolling interest in Calpeco, APUC received $38.7 million from Emera related to the issuance of 8,211,000 subscription receipts which were issued at a price of $4.72 per subscription receipt. On December 27, 2012, APUC issued 4,790,000 Common Shares and on February 14, 2013, APUC issued 3,421,000 Common Shares upon conversion of these subscription receipts.

Subsequent to the end of 2012, in connection with the closing of the acquisition of the Minonk and Senate wind facilities from Gamesa USA, that occurred on December 10, 2012, APUC issued (i) on February 7, 2013, 2,614,005 Common Shares upon the conversion of subscription receipts that were issued at a price of $5.74 per subscription receipt and (ii) on February 14, 2013, 5,228,011 Common Shares upon the conversion of subscription receipts that were issued at a price of $5.74 per subscription receipt. The total $45 million in cash proceeds from the conversion of the subscription receipts were used at the time of the acquisition closing to fund a portion of the cost of the acquisition.

On March 26, 2013, in connection with the acquisition of the Georgia Utility, APUC issued 3,960,000 Common Shares at a price of $7.40 per share to Emera for total proceeds of approximately $29 million.

As at March 26, 2013, in total Emera now owns 50,126,766 Common Shares, representing approximately 24.51% of the outstanding Common Shares of APUC. 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.

6.3 Preferred Shares

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.

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

As at December 31, 2012, APUC had 4.8 million Series A Shares outstanding.

Effective January 1, 2013, APUC issued an aggregate of 100 Series C preferred shares to the holders of the Class B units of St. Leon LP, in exchange for such Class B units. See *"General Development of the Business – Recent Developments – 2013 – Corporate – Agreement with St. Leon Class B unit holders*".

6.4 Convertible Debentures

(a) Series 1A Debentures

On October 27, 2009, the Corporation issued, in connection with the Unit Exchange, an aggregate of $66,942,750 principal amount Series 1A Debentures.

On April 7, 2011, APUC provided the holders of its Series 1A Debentures with notice of its intention to redeem for equity, all of the issued and outstanding Series 1A Debentures. Prior to the Series 1A Redemption Date (May 16, 2011), a principal amount of $60,339,000 of Series 1A Debentures were converted into 14,788,975 Common Shares. On the Series 1A Redemption Date, APUC issued and delivered 430,666 Common Shares to the remaining holders of the Series 1A Debentures, representing the number of freely tradable Common Shares obtained by dividing the aggregate principal amount of Debentures, by 95% of the current market price of Common Shares on the Series 1A Redemption Date.

As a result of the redemption there were no Series 1A Debentures outstanding subsequent to the Series 1A Redemption Date.

(b) Series 2A Debentures

On October 27, 2009, the Corporation issued, in connection with the Unit Exchange, an aggregate of $59,967,000 principal amount of Series 2A Debentures.

On January 20, 2012, APUC provided the holders of its Series 2A Debentures notice of its intention to redeem for equity, effective on the Series 2A Redemption Date (February 24, 2012), all of the issued and outstanding Series 2A Debentures. Prior to the Series 2A Redemption Date, $2,916,000 principal amount of Series 2A Debentures were converted by debenture holders into 485,998 Common Shares.

On the Series 2A Redemption Date, APUC issued and delivered 9,836,520 APUC shares to the remaining holders of Series 2A Debentures, representing the number of freely tradable APUC shares obtained by dividing the aggregate principal amount of Debentures of $57,041,000, by 95% of the current market price of Common Shares on the Series 2A Redemption Date.

As a result, there are no Series 2A Debentures outstanding subsequent to the Series 2A Redemption Date.

(c) Series 3 Debentures

On December 2, 2009, APUC issued $63,250,000 principal amount of Series 3 Debentures.

On November 19, 2012, APUC announced its intent to redeem on the Series 3 Redemption Date (January 1, 2013) all of the outstanding Series 3 Debentures at such date. During the year ended December 31, 2012, a principal amount of $61.6 million Series 3 Debentures were converted into 14,669,266 shares of APUC. The Series 3 Debentures were convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share. On December 31, 2012, there was $0.96 million principal amount of Series 3 Debentures outstanding. On January 1, 2013, APUC redeemed the outstanding Series 3 Debentures and issued 150,816 shares as a result of the redemption. Following the redemption, there were no Series 3 Debentures outstanding.

6.5 Employee Share Purchase Plan

APUC has an employee share purchase plan ("**ESPP**") in place that provides eligible employees the opportunity to have a portion of their earnings withheld to be used to purchase common shares of APUC. APUC will match up to 20% of an employee's contribution amount for the first $5,000 contributed annually and 10% of an employee's contribution amount for contributions over $5,000 and up to $10,000 annually. Shares purchased through the APUC matched portion vest over a one year period. At APUC's option, the shares may be (i) issued to participants from treasury at the weighted average share price at time of issue or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. As at December 31, 2012, a total of 61,403 shares had been issued under the ESPP. For the year ended December 31, 2012, APUC issued 54,225 shares under the ESPP and recorded $42 in compensation expense.

6.6 Directors Deferred Share Units

The Deferred Share Unit Plan provides the opportunity for non-employee directors of APUC to elect annually to receive all or any portion of their compensation in deferred share units ("**DSU**") 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 APUC common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSU's in cash, these DSUs are accounted for as equity awards.

As at December 31, 2012, a total of 50,170 DSUs had been issued under the Deferred Share Unit Plan.

6.7 Performance Share Units

As at December 31, 2012, APUC had issued 21,123 performance share units (" **PSUs**") to certain members of management other than senior executives as part of APUC's long-term incentive program. At the end of the three-year performance periods, the number of shares vested can range from 0% to 144% of the number of PSUs granted. Dividends accumulate during vesting periods and are converted to PSUs based on the market value of the shares on that date. None of the 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 APUC. As APUC does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized rateably over the performance period based on APUC's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage.

6.8 Shareholders' Rights Plan

The Rights Plan is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the board of directors of the Corporation and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value. The Rights Plan was approved by

shareholders at the Meeting until the termination of the annual general meeting of the shareholders of APUC in 2013 or its termination under the terms of the of Rights Plan. The Rights Plan is similar to rights plans adopted by many other Canadian corporations. Until the occurrence of certain specific events, the rights will trade with the Common Shares of APUC and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it, with the exception of Emera, acquires or announces its intention to acquire twenty percent or more of the outstanding Common Shares without complying with the Permitted Bid provisions of the Plan. The application of the Rights Plan to acquisition of Shares by Emera under Allowed Transactions was waived following shareholder approval at the Annual and Special Meeting of Shareholders on June 21, 2010. Should a non-Permitted Bid be launched, each right would entitle each holder of shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional Common Shares at a fifty percent discount to the market price at the time.

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

APUC has asked shareholders to approve an amendment and the continuance of the Rights Plan at the annual shareholders' meeting scheduled for April 23, 2013.

6.9 Stock Option Plan

The Corporation implemented a stock option plan (the "**Stock Option Plan**") in 2010. The purpose of the Stock Option Plan is to attract, retain and motivate persons as key service providers to the Corporation and its affiliates and to advance the interests of the Corporation by providing such persons with the opportunity, through share options, to acquire a proprietary interest in the Corporation.

The Stock Option Plan authorizes the Board to issue stock options (" **Options**") to directors, officers or employees of the Corporation or any affiliate (an "**Eligible Individual**"), a corporation controlled by an Eligible Individual or any person/company, partnership, trust or corporation engaged to provide management or consulting services for the Corporation or any affiliate ("**Eligible Persons**").

The aggregate number of Common Shares that may be reserved for issuance under the Stock Option Plan must not exceed 10% of the number of Common Shares outstanding at the time the Options are granted. For greater clarity, the Stock Option Plan is "reloading" in the sense that, to the extent that Options expire or are terminated, cancelled or exercised, the Corporation may make a further grant of Options in replacement for such expired, terminated, cancelled or exercised Options, provided that the 10% maximum is not exceeded. No fractional Common Shares may be purchased or issued under the Stock Option Plan.

In addition, under the Stock Option Plan:

- subject to the terms of the Stock Option Plan, the number of Common Shares subject to each Option, the exercise price of each Option, the expiration date of each Option, the extent to which each Option vests and is exercisable from time to time during the term of the Option and other terms and conditions relating to each Option will be determined by the Board from time to time;

- subject to any adjustments pursuant to the provisions of the Stock Option Plan, the exercise price of any Option shall in no circumstances be lower than the Market Price (as defined below) of the Common Shares on the date on which the Board approves the grant of the Option;
- Options will be personal to the grantee and will be non-transferable and non-assignable, except in certain limited circumstances;
- the maximum number of Common Shares which may be reserved for issuance to insiders under the Stock Option Plan, together with the number of Common Shares reserved for issuance to insiders under any other securities based compensation arrangement, shall be 10% of the Common Shares outstanding at the time of the grant;
- the maximum number of Common Shares which may be issued to insiders under the Stock Option Plan and all other security based compensation arrangements within a one year period shall be 10% of the Common Shares outstanding at the time of the issuance;
- non-employee director participation in the Stock Option Plan is limited to the lesser of (i) a reserve of 1% of the Common Shares outstanding for non-employee directors as a group and (ii) an annual equity award value of $100,000 per director;
- if the expiration date for an Option occurs during a Blackout Period (as defined below) or within 10 business days after the expiry date of a Blackout Period applicable to a person granted Options (an "**Optionee**"), then the expiration date for that option will be extended to the 10th business day after the expiry date of the Blackout Period. A "**Blackout Period**" is a period of time of time during which the Optionee cannot exercise an Option, or sell Common Shares issuable pursuant to the exercise of Options, due to applicable policies of the Corporation in respect of insider trading); and
- except in certain circumstances, the term of an Option shall not exceed ten (10) years from the date of the grant of the Option.

Under the Stock Option Plan, "**Market Price**" of the Common Shares is defined as the volume weighted average trading price of such Common Shares on the TSX (or, if such Common Shares are not then listed and posted for trading on the TSX, on such stock exchange in Canada on which such Common Shares are listed and posted for trading as may be selected for such purpose by the Board) for the five (5) consecutive trading days immediately preceding such date, provided that in the event that such Common Shares did not trade on any of such trading days, the Market Price will be the average of the bid and ask prices in respect of such Common Shares at the close of trading on all of such trading days and provided that in the event that such Common Shares are not listed and posted for trading on any stock exchange, the Market Price will be the fair market value of such Common Shares as determined by the Board in its sole discretion.

The Stock Option Plan provides that, except as set out in the Stock Option Plan or any resolution passed at any time by the Board or the terms of any option agreement or employment agreement with respect to any Option or an Optionee, an Option and all rights to purchase Common Shares pursuant thereto shall expire and terminate immediately upon the Optionee who holds such Option ceasing to be an Eligible Person.

Where an Optionee (other than a service provider) resigns from the Corporation or is terminated by the Corporation for cause, the Optionee's unvested options shall immediately be forfeited and the Optionee's vested options may be exercised for a period of 30 days after the date of resignation or termination.

Where an Optionee (other than a service provider) retires from the Corporation or ceases to serve the Corporation or an affiliate as a director, officer or employee for any reason other than a termination by the Corporation for cause, the Optionee's unvested options may be exercised within 90 days after such retirement or termination. The Board may in such circumstances accelerate the vesting of unvested Options then held by the Optionee at the Board's discretion.

In the event that an Optionee, other than a service provider, has suffered a permanent disability, Options previously granted to such Optionee shall continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the Stock Option Plan, but no additional grants of Options may be made to the Optionee.

If an Optionee, other than a service provider, dies, all unexercised Options held by such Optionee at the time of death immediately vest, and such Optionee's personal representatives or heirs may exercise all Options within one year after the date of such death.

All Options granted to service providers shall terminate in accordance with the terms, conditions and provisions of the associated option agreement between the Corporation and such service providers, provided that such termination shall occur no later than the earlier of (i) the original expiry date of the term of the Option and (ii) one year following the date of termination of the engagement of the service provider.

Options may be exercised in accordance with the specific terms of their grant and by the Optionee delivering the exercise price to the Corporation for all of the Options exercised. The Optionee may also surrender Options and receive in exchange for each such Option, the amount by which the Market Price of the Common Shares exceeds the exercise price of the Option (the "**In-the-Money Amount**"). If the Optionee elects to surrender any Options in exchange for the In-the-Money Amount, the Corporation will determine whether to pay such amount in cash or in Common Shares representing the equivalent of the In-the-Money Amount based on the Market Price of the Common Shares at the date of exercise, in each case net of an amount equal to any withholding taxes.

In the event that the Common Shares are at any time changed or affected as a result of the declaration of a stock dividend, a Share subdivision or consolidation, the number of Common Shares reserved for Option shall be adjusted accordingly by the Board to such extent as it deems proper in its discretion.

If, after the grant of an Option and prior to its expiry:

(i) the Common Shares are reclassified, reorganized or otherwise changed (a " **Share Reorganization**"), otherwise than as specified in the immediately preceding paragraph, or

(ii) subject to the Corporation's right to allow the exercise of vested and unvested Options following the occurrence of certain transactions, the Corporation shall consolidate, merge or amalgamate with or into another corporation (a "**Merger**", with the resulting corporation being the "**Successor Corporation**"),

the Optionee will receive, upon the subsequent exercise of his or her Options in accordance with the Stock Option Plan, the number of Common Shares or securities of the appropriate class of the Corporation or Successor Corporation, as the case may be, that the Optionee would have received if on the record date of such Share Reorganization or Merger the Optionee were the registered holder of the number of Common Shares to which the Optionee was prior thereto entitled to receive on exercise of his or her Options.

The Board may amend, suspend or discontinue the Stock Option Plan or amend Options granted under the Stock Option Plan at any time without shareholder approval; provided, however, that:

(a) approval by a majority of the votes cast by shareholders present and voting in person or by proxy at a meeting of shareholders of the Corporation shall be obtained for the following amendments:

  (i) any amendment for which, under the requirements of the TSX or any applicable law, shareholder approval is required;

  (ii) reduction of the exercise price, or cancellation and reissuance of Options or other entitlements, of non-insider Options granted under the Stock Option Plan;

  (iii) extension of the term of Options beyond the original expiry date of non-insider Options;

  (iv) change in Eligible Participants that may permit an increase to the limit imposed on non-employee director participation;

  (v) permitting of Options granted under the Stock Option Plan to be transferable or assignable other than for estate settlement purposes; or

  (vi) amendment to the Stock Option Plan's amendment provisions; and

(b) the consent of the Optionee is obtained for any amendment which alters or impairs any Option previously granted to an Optionee under the Stock Option Plan.

Notwithstanding the other provisions of the Stock Option Plan, if:

(a) the Corporation proposes to amalgamate, merge or consolidate with any other corporation (other than a wholly-owned affiliate) or to liquidate, dissolve or wind-up;

(b) an offer to purchase or repurchase all of the Common Shares shall be made to all holders of Common Shares which offer has been approved or accepted by the Board; or

(c) the Corporation proposes the sale of all or substantially all of the assets of the Corporation as an entirety, or substantially as an entirety, so that the Corporation shall cease to operate any active business,

then, the Corporation will have the right, upon written notice thereof to Optionees, to permit the exercise of all such Options, whether or not vested, within the 20 day period next following the date of such notice and to determine that upon the expiration of such 20 day period, all rights of the Optionee to such Options or to exercise same (to the extent not theretofore exercised) shall *ipso facto* terminate and cease to have further force or effect whatsoever.

As of March 30, 2012 the number of outstanding options is 3,681,710, which is 2.5% of the total outstanding Common Shares of the Corporation. The number of Common Shares that have been issued pursuant to the plan is nil.

7. MARKET FOR SECURITIES

7.1 Trading Price and Volume

(a) **Common Shares**

APUC's Common Shares are listed and posted for trading on the TSX under the symbol "AQN". The following table sets forth the high and low closing prices and the aggregate volume of trading of the Common Shares and trust units for the periods indicated (as quoted by the TSX).

2012	High ($)	Low ($)	Volume (000's)
January	6.45	5.99	11,783
February	6.22	6.01	8,365
March	6.43	5.76	12,505
April	6.35	5.68	12,802
May	6.40	6.11	6,360
June	6.70	6.20	8,209
July	6.88	6.49	5,381
August	6.84	6.57	4,899
September	6.69	6.47	11,377
October	6.97	6.64	5,166
November	6.89	6.60	10,842
December	6.89	6.58	7,152

(b) **Preferred Shares**

APUC's Series A Shares became listed and started trading under the symbol "AQN.PR.A" on November 9, 2012.

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series A Shares for the periods indicated (as quoted by the TSX).

2012	High ($)	Low ($)	Volume (000's)
November	25.00	24.91	666
December	25.28	24.90	255

(c) **Series 2A Debentures**

Series 2A Debentures were listed and posted for trading on the TSX under the symbol "AQN.DB.A". On the Series 2A Redemption Date, the remaining Series 2A Debentures were redeemed. As a result, there are no Series 2A Debentures outstanding subsequent to the Series 2A Redemption Date.

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 2A Debentures for the periods indicated (as quoted by the TSX).

2012	High ($)	Low ($)	Volume (000's)
January	108.50	102.50	11,013
February 1 – 24	106.52	103.13	17,679

(d) **Series 3 Debentures**

Series 3 Debentures were listed and posted for trading on the TSX under the symbol “AQN.DB.B”. On the Series 3 Redemption Date, the remaining Series 3 Debentures were redeemed. As a result, there are no Series 3 Debentures outstanding subsequent to the Series 3 Redemption Date.

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 3 Debentures for the periods indicated (as quoted by the TSX).

2012	High ($)	Low ($)	Volume (000’s)
January	154.11	144.05	8,929
February	149.19	144.00	2,706
March	153.14	140.17	939
April	151.66	136.76	4,815
May	153.20	147.04	9,571
June	159.28	150.52	1,721
July	165.00	156.52	562
August	163.15	158.18	493
September	160.37	154.49	15,731
October	167.50	160.89	340
November	166.00	156.98	22,532
December	165.00	137.40	4,873

7.2 Prior Sales

During the year ended December 31, 2010, 1,160,204 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $4.05. One-third of the options vested on each of January 1, 2011, 2012 and 2013.

During the year ended December 31, 2011, the Board approved the following grant of options:

- On March 22, 2011, 892,107 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $5.23;
- On June 21, 2011, 171,642 options were granted to a senior executive of APCo which allow for the purchase of common shares at a price of $5.64;
- On July 28, 2011, 90,909 options were granted to a senior executive of APUC which allow for the purchase of common shares at a price of $5.74; and
- On September 13, 2011, 172,242 options were granted to a senior executive of Liberty Utilities which allow for the purchase of common shares at a price of $5.65.

In each case, one-third of the options vest on each of January 2012, 2013, and 2014.

On March 14, 2012, 1,194,606 options were granted to senior executives of APUC and senior managers which allow for the purchase of common shares at a price of $6.22. One-third of the options vest on each of January 1, 2013, 2014 and 2015.

On March 14, 2013, 816,402 options were granted to senior executives of APUC and senior managers which allow for the purchase of common shares at a price of $7.72. One-third of the options vest on each of January 2014, 2015, and 2016.

All options were issued using the five day volume weighted average price of the underlying common shares at the date of the grant. In all cases, Options may be exercised up to eight years following the date of grant. During the year ended December 31, 2012, no options were exercised. As at December 31, 2012, APUC had 3,750,726 options issued and outstanding. As at December 31, 2012, 1,215,770 options were exercisable. No share options were exercised in 2012 or 2011.

	Number of shares	Weighted average exercise price	Weighted average remaining contractual term
Balance at January 1, 2012	2,487,104	$ 4.76	6.56
Granted	1,263,622	6.24	8.00
Balance at December 31, 2012	3,750,726	$ 5.26	7.04
Exercisable at December 31, 2012	1,215,770	$ 4.53	6.28

In addition, APUC issued Common Shares to Emera upon the conversion of subscription receipts in 2012 and 2013 and issued Common Shares to Emera upon a private placement in March 2013 as described under "*Description of Capital Structure – Private Placements of Subscription Receipts and Common Shares to Emera*".

7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer

The following securities of APUC are subject to contractual restrictions on transfer as of the date of this AIF:

Description	Number of Securities held in escrow	Percentage of class
Common Shares	50,126,766	**24.51%**

The Common Shares noted above are owned by Emera. Holdings of Common Shares by Emera up to 15% of the outstanding common shares are subject to certain restrictions on transfer and certain voting covenants until January 1, 2014 contained in a subscription and unitholder agreement dated April 22, 2009, as amended, between Emera and APUC. Holdings of Common Shares by Emera greater than 15% and up to 25% of the outstanding common shares are subject to a limited restriction on transfer and certain voting covenants contained in the Strategic Investment Agreement.

8. DIRECTORS AND OFFICERS

8.1 Name, Occupation and Security Holdings

The following table sets forth certain information with respect to the directors and executive officers of APUC, and information on their history with APCo. Unless otherwise indicated, the individuals have been in their principal occupations for more than five years.

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares	Number of Deferred Share Units
CHRISTOPHER J. BALL Toronto, Ontario, Canada Age: 62	Christopher Ball is the Executive Vice President of Corpfinance International Limited, and President of CFI Capital Inc., both of which are investment banking boutique firms. From 1982 to 1988, Mr. Ball was Vice President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held various managerial positions with the Canadian Imperial Bank of Commerce. He is also a member of the Hydrovision International Advisory Board, and was a director of Clean Energy BC, with his term ending in June 2011.	Director of APUC since October 27, 2009. Trustee of APCo since October 22, 2002	24,200	11,238
KENNETH MOORE Toronto, Ontario, Canada Age: 54	Kenneth Moore is the Managing Partner of NewPoint Capital Partners Inc., an investment banking firm. From 1993 to 1997, Mr. Moore was a senior partner at Crosbie & Co., a Toronto mid-market investment banking firm. Prior to investment banking, he was a Vice-President at Barclays Bank where he was responsible for a number of leveraged acquisitions and restructurings. Mr. Moore holds a Chartered Financial Analyst designation. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Director of APUC since October 27, 2009. Trustee of APCo since December 18, 1998	18,000	26,078
GEORGE L. STEEVES Aurora, Ontario, Canada Age: 62	George Steeves is the principal of True North Energy, an energy consulting firm. From January 2001 to April 2002, Mr. Steeves was a division manager of Earthtech Canada Inc. Prior to January 2001, he was the president of Cumming Cockburn Limited, an engineering firm, and has extensive financial expertise in acting as a chair, director and/or audit committee member of public and private companies, including the Corporation, and formerly Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves received a Bachelor and Masters of Engineering from Carleton University and holds the Professional Engineering designation in Ontario and British Columbia. Additionally he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Director of APUC since October 27, 2009. Trustee of APCo since September 8, 1997	17,241(1)	12,854

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares	Number of Deferred Share Units
CHRISTOPHER HUSKILSON Wellington, Nova Scotia, Canada Age: 55	Christopher Huskilson has been the President and Chief Executive Officer of Emera, a North American energy and services company, since November 2004. He was Chair of the Technology and Development Committee until its dissolution in February 2012. He is also Chair of Bangor Hydro Electric Company, a Director of Nova Scotia Power Inc. and serves as the Chair or as a Director of a number of other Emera affiliated companies. Mr. Huskilson has held a number of positions within Nova Scotia Power Inc. and its predecessor, Nova Scotia Power Corporation, since June 1980. Mr. Huskilson holds a Bachelor of Science in Engineering and a Master of Science in Engineering from the University of New Brunswick.	Director of APUC since October 27, 2009. Trustee of APCo since July 27, 2009	nil [2]	nil [2]
DAVID BRONICHESKI Oakville, Ontario, Canada Age: 53	Mr. Bronicheski is the Chief Financial Officer ("**CFO**") of APUC. He has held various senior management positions including Executive Vice President and CFO of a publicly traded income trust providing local telephone, cable television and internet service. He was also CFO for a large public hospital in Ontario. Mr. Bronicheski holds a Bachelor of Arts in economics (cum laude), a Bachelor of Commerce degree and an MBA. He is also a Chartered Accountant.	Officer of APUC since October 27, 2009. Officer of APCo since September 17 2007[3] [4]	40,000[7] [8] [9][12]	N/A
CHRISTOPHER K. JARRATT[5] [6] Oakville, Ontario, Canada Age: 54	Christopher Jarratt is the Vice Chair of the Corporation. Mr. Jarratt is a founder and principal of Algonquin Power Corporation Inc., a private independent power developer formed in 1988 which was a predecessor organization to APUC. Mr. Jarratt has over 25 years of experience in the development of independent electric power generating projects both in North America and internationally. Mr. Jarratt was also a founder and principal of a consulting firm specializing in renewable energy project development. Mr. Jarratt is a water resources engineer and holds a Professional Engineering designation through his Honours Bachelor of Science degree from the University of Guelph. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dr. (Chartered Director).	Director of APUC since June 23, 2010.	410,309[7] [8] [9][11][12]	N/A

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares	Number of Deferred Share Units
IAN E. ROBERTSON[5] [6] Oakville, Ontario, Canada Age: 53	Ian Robertson is the Chief Executive Officer of the Corporation. Mr. Robertson is a founder and principal of Algonquin Power Corporation Inc., a private independent power developer formed in 1988 which was a predecessor organization to APUC. Mr. Robertson has over 23 years of experience in the development of electric power generating projects. Mr. Robertson is an electrical engineer and holds a Professional Engineering designation through his Bachelor of Applied Science degree awarded by the University of Waterloo. Mr. Robertson earned a Master of Business Administration degree from York University and holds a Chartered Financial Analyst designation. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Director of APUC since June 23, 2010.	427,905[7] [8] [9][12]	N/A
LINDA BEAIRSTO Oakville, Ontario, Canada Age: 52	Ms. Beairsto has been Chief General Counsel and Corporate Secretary for APUC since June 2011. Previously, she held various diverse roles including Commercial Real Estate Lawyer at Fasken Martineau, Special Counsel at E.I. du Pont Canada Inc., Director of Legal Services at Patheon Inc., Executive Vice-President & Chief Legal Counsel at ABC Group of Companies and Special Counsel at Allergan Inc. Linda holds a Bachelor of Arts Degree from the University of British Columbia and a Bachelor of Laws Degree from the University of New Brunswick. She was called to the bar in Ontario in 1990.	Officer of APUC since June 6, 2011	1,504[9] [10][12]	N/A

Notes:

(1) Mr. Steeves' directly owns 14,327 Common Shares and Mr. Steeves' spouse owns 2,914 Common Shares. Mr. Steeves exercises control and direction over the Common Shares owned by his spouse.
(2) Mr. Huskilson does not own any Common Shares or Deferred Share Units.
(3) Mr. Bronicheski became an officer of APCo on September 17, 2007.
(4) Prior to becoming an officer of APCo in September 2007, Mr. Bronicheski was the CFO of Amtelecom Income Fund from July 2003 to July 2007.
(5) Messrs. Jarratt and Robertson, together with others, collectively own all of the issued and outstanding shares of APMI.
(6) As consideration for payment of APUC's acquisition of APMI's interest in the management agreement, Mr. Robertson and Mr. Jarratt following shareholder approval at the Meeting each received 295,045 Common Shares.
(7) Messrs. Jarratt, Robertson, and Bronicheski hold 436,224, 494,388, and 229,593 stock options respectively, granted on August 12, 2010. The stock options allow for the purchase of Common Shares at a price of $4.05. One-third of the stock options vested on each of January 1, 2011, 2012 and 2013. Stock options may be exercised up to eight years following the date of grant.

(8) Messrs. Jarratt, Robertson, and Bronicheski hold 335,423, 380,146, and 176,538 stock options respectively, granted on March 22, 2011. The stock options allow for the purchase of Common Shares at a price of $5.23. One-third of the stock options vests on each of January 1, 2012, 2013 and 2014. Stock options may be exercised up to eight years following the date of grant.
(9) Ms. Beairsto and Messrs. Jarratt, Robertson, and Bronicheski hold 85,000, 267,963, 350,413, and 162,917 stock options respectively, granted on March 14, 2012. The stock options allow for the purchase of Common Shares at a price of $6.22. One-third of the stock options vests on each of January 1, 2013, 2014, and 2015. Stock options may be exercised up to eight years following the date of grant.
(10) Ms. Beairsto holds 90,909 stock options granted on July 28, 2011, that allow for the purchase of Common Shares at a price of $5.74. One-third of the stock options vests on January 1, 2012, 2013, and 2014. Stock options may be exercised up to eight years following the date of grant.
(11) Messr Jarratt holds 38,548 stock options, granted on June 19, 2012. The stock options allow for the purchase of Common Shares at a price of $6.56. One third of the stock options vest on each of January 1, 2013, 2014, and 2015.
(12) Ms. Beairsto and Messrs. Jarratt, Robertson, and Bronicheski hold 65,854, 228,293, 285,366, and 91,463 stock options respectively, granted on March 14, 2013. The stock options allow for the purchase of Common Shares at a price of $7.72. One-third of the stock options vests on each of January 1, 2014, 2015, and 2016. Stock options may be exercised up to eight years following the date of grant.

Each director will serve as a director of APUC until the next annual meeting of shareholders or until his or her successor is elected in accordance with the by-laws of APUC (the "**By-Laws**").

As of March 26, 2013, approximately 895,712 Common Shares representing 0.45% of the issued and outstanding Common Shares are beneficially owned, directly or indirectly, by Senior Executives and approximately 955,153 Common Shares representing 0.48% of the issued and outstanding Common Shares are beneficially owned, directly or indirectly, by the directors and executive officers of the Corporation.

8.2 Audit Committee

Under the By-Laws, the directors may appoint from their number, committees to effect the administration of the director's duties. The directors have established an Audit Committee comprised of three directors of APUC, Mr. Ball (Chairman), Mr. Moore and Mr. Steeves, all of whom are independent and financially literate for purposes of National Instrument 52-110 – *Audit Committees*. The Audit Committee is responsible for reviewing significant accounting, reporting and internal control matters, reviewing all published quarterly and annual financial statements and recommending their approval to the Directors and assessing the performance of APUC's auditors.

(a) Audit Committee Charter

The charter for APUC's audit committee (the "**Audit Committee**") is attached as Schedule E to this AIF.

(b) Relevant Education and Experience

The following is a description of the education and experience, apart from their roles as Directors of APUC, of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee.

Mr. Ball has extensive financial experience, with over 30 years of domestic and international lending experience. He is Executive Vice-President of Corpfinance International Limited, a privately owned long-term debt and securitization financier. Mr. Ball was formerly a Vice-President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch

operation. Prior to that, Mr. Ball held numerous positions with Canadian Imperial Bank of Commerce, including credit function responsibilities. Mr. Ball is the Chair of the Audit Committee.

Mr. Moore has extensive financial experience and is the Managing Partner of NewPoint Capital Partners Inc., a boutique financial advisory firm focused on mergers and acquisitions. He was formerly a Vice-President at a Canadian Chartered Bank. Mr. Moore holds a Chartered Financial Analyst and a Chartered Director designation.

Mr. Steeves received a Bachelor and Masters of Engineering from Carleton University. Mr. Steeves is the former president of Cumming Cockburn Limited and has extensive financial experience in acting as a Chairman, director and/or audit committee member of public and private companies, including APCo, Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir. (Chartered Director). He received a Bachelor and Masters of Engineering from Carleton University and holds the Professional Engineering designation in Ontario and British Columbia.

(c) **Pre-Approval Policies and Procedures**

All non-audit services proposed to be provided by APUC's auditors must be approved by the Directors prior to the auditors providing such services.

For the financial year ended December 31, 2012 and December 31, 2011, KPMG LLP charged the following fees to APUC:

Services	2012 Fees ($)	2011 Fees ($)
Audit Fees[1]	1,346,100	1,330,000
Audit-Related Fees[2]	316,925	278,000
Tax Compliance Fees[3]	614,700	475,150
Other Tax Fees[4]	481,371	432,700
All Other Fees	25,000	Nil

Notes:

(1) For professional services rendered for audit or review or services in connection with statutory or regulatory filings or engagements. The 2012 fees include additional costs related to APCo private placement and APUC equity offering.
(2) For assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and not reported under Audit Fees, including accounting advice and French translation services.
(3) For preparation of income and other tax filings.
(4) For tax advice and planning services

8.3 Corporate Governance and Compensation Committees

The directors have also established a Corporate Governance Committee (" **CGC**") comprised of three of the directors of APUC, Mr. Steeves (Chair), Mr. Huskilson and Mr. Moore. The CGC includes two members of management by invitation, Mr. Robertson and Mr. Jarratt. The mandate of the CGC includes:

- Review APUC's corporate governance practices;

- Consider and make recommendations to the board from time to time regarding the effectiveness of the Directors and whether an increase to the number of directors is warranted;
- Conduct periodic reviews of the mandates of the Board and its committees, including recommending to the Board amendments to such mandates;
- Annually approve a Statement of Corporate Governance; and
- Recommend procedures to permit the Board to function independently of management.

The directors have also put in place a Compensation Committee (" **CC**"), comprised of Directors Mr. Huskilson (Chair) and Mr. Ball. The CC includes two members of management by invitation, Mr. Robertson and Mr. Jarratt.

The CC shall exercise the responsibilities and duties set forth below, including but not limited to:

- Selecting and appointing the CEO of the Corporation;
- Approving executive compensation plan (including philosophy and guidelines);
- Recommending to the Board compensation arrangements for the CEO and reviewing and approving compensation arrangements for Designated Employees and Directors;
- Reviewing and approving management succession plans; and
- Approving the grant of stock options.

8.4 Bankruptcies

Mr. Moore was a director of Telephoto Technologies Inc., a private sports and entertainment media. Telephoto Technologies Inc. was placed into receivership in August, 2010 by Venturelink Funds. Mr. Moore resigned from the board of directors of Telephoto Technologies Inc. in April, 2010.

David Pasieka, the President of Liberty Energy Utilities Co., a wholly-owned indirect subsidiary of APUC, was a director of Luxell Technologies Inc. when it filed a proposal under the *Bankruptcy and Insolvency Act (Canada)* on September 27, 2006. Luxell Technologies Inc. received a Certificate of Full Performance of Proposal under such legislation through a letter issued by its trustee in bankruptcy on January 14, 2008.

8.5 Potential Material Conflicts of Interest

Other than as set out below or disclosed elsewhere in this AIF and APUC's financial statements and management's discussion and analysis for the fiscal year ended December 31, 2012, APUC is not aware of any existing or potential material conflicts of interest between APUC or a subsidiary and any current director or officer of APUC or a subsidiary. Mr. Huskilson is a director of APUC but also the President and CEO of Emera. Emera is a major shareholder of APUC. Emera has a strategic relationship with APUC, see "*Material Contracts*". Mr. Huskilson does not vote in Board meetings on matters involving APUC's relationship with Emera nor on matters involving a potential conflict between APUC and Emera.

9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS

9.1 Legal Proceedings

Except as disclosed elsewhere in this AIF, the only legal proceedings involving APUC or its subsidiaries that were material in 2012 are as follows:

(a) Trafalgar

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

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

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

(b) Côte Ste-Catherine Water Lease Dues

On October 21, 2011 the Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5.4 million (including interest) to the government of Québec relating to water lease payments that the APUC subsidiary has been paying to the Seaway Management under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $5.8 million. In 2012, the subsidiary of APUC paid an amount of $1.884 million (2011 – $ nil) to the government of Québec in relation to the early years covered by the claim in order to mitigate the impact of accruing interests on any amount ultimately determined to be payable or recoverable. The parties are attempting to resolve this matter through good faith negotiations.

9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2012, there have been:

(a) no penalties or sanctions imposed against APUC by a court relating to securities legislation or by a securities regulatory authority;

(b) no other penalties or sanctions imposed by a court or regulatory body against APUC that would likely be considered important to a reasonable investor in making an investment decision; or

(c) no settlement agreements that APUC has entered into with a court relating to securities legislation or with a securities regulatory authority.

10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed elsewhere in this AIF, and as disclosed in APUC's annual financial statements and management's discussion and analysis as at and for the periods ended December 31, 2012, 2011, and 2010, management has no material interest, direct or indirect, in any transaction occurring within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect APUC.

11. TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Common Shares and the Series A Shares is CIBC Mellon Trust Company, at its offices in Toronto, Montréal, Vancouver, Calgary, and Halifax. Canadian Stock Transfer Company Inc. acts as the Administrative Agent for CIBC Mellon Trust Company.

12. MATERIAL CONTRACTS

Except for certain contracts entered into in the ordinary course of business of APUC and its subsidiaries, the contracts described below are the only contracts entered into by APUC or its subsidiaries during 2012 (or prior to 2011 in the case of contracts that are still in effect) that are material to APUC. It is worthy of note that Transfer Agreements dated December 21, 2009 with each of the principals of APMI that transferred their interests in the Management Agreement (as discussed in the Management Information Circular dated June 1, 2010) were approved in 2010 by the Shareholders at the Meeting as well as the TSX. The previously disclosed material contracts with Management have all been terminated as they pertain to APUC. These are the Management Agreement, the Operations Supervisory Agreement, the Administration Agreement, the Governance Agreement and the Direct Operations Agreements.

(a) **U.S. Wind Farm Portfolio:** Third Amended and Restated Membership Interest Purchase and Sale Agreement entered into as of October 9, 2012 (amending and restating the 51% Membership Interest Purchase and Sale Agreement dated December 30, 2011, as previously amended and restated as of March 8, 2012 and as of June 29, 2012), by and among APFA and Gamesa USA ("**MIPA**"). Amendment and Waiver to the MIPA, entered into as of December 10, 2012, by and among APFA and Gamesa USA. 51% MIPA Guarantee dated as of March 8, 2012 made by APUC in favor of Gamesa USA. 51% MIPA Guarantee dated as of March 8, 2012 made by Gamesa Corporación Technológica, S.A. in favor of APFA.

Second Amended and Restated Indemnification Agreement entered into as of October 9, 2012 (amending and restating the Indemnification Agreement entered into as of dated March 8, 2012, as previously amended and restated as of June 29, 2012), by and among Gamesa USA, Gamesa Corporación Technológica, S.A., Wind Portfolio Sponsorco, LLC, and APFA

(b) **Midwest Gas Utilities Acquisition:** An Asset Purchase Agreement entered into on May 12, 2011 between Atmos Energy Corporation, as seller, and Liberty Midstates, as buyer to acquire certain regulated natural gas distribution utility systems located in the States of Missouri, Iowa, and Illinois. Guaranty dated as of May 12, 2011 made by APUC as guarantor, in favour of Atmos. The transaction was completed on August 1, 2012.

(c) **Georgia Utility Acquisition:** An Asset Purchase Agreement entered into on August 8, 2012 between Atmos, as seller, and Liberty Georgia, as buyer to acquire certain regulated natural gas distribution utility systems located in the State of Georgia. Guaranty dated as of August 8, 2012 made by APUC as guarantor, in favour of Atmos. Closing is expected to occur on or about April 1, 2013.

(d) **APCo debentures:** APCo Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of senior unsecured debentures from time to time. A First Supplemental Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of $135,000,000 5.50% senior unsecured debentures due July 25, 2018. The notes are interest only until maturity. The funds were used to repay the Airsource Senior Debt and to reduce outstanding indebtedness under the APCo Credit Facility. Second Supplemental Trust Indenture between APCo and BNY Trust Company of Canada dated December 3rd, 2012 providing for the issuance of $150,000,000 4.82% senior unsecured debentures due February 15, 2021.

(e) **Emera Strategic Investment Agreement:** Strategic Investment Agreement between APUC and Emera dated April 29, 2011 which establishes how APUC and Emera will work together to pursue specific strategic investments of mutual benefit. The Strategic Investment Agreement was approved by shareholders at the annual and special general meeting held on June 21, 2011.

(f) **LU credit agreement:** Credit Agreement dated January 18, 2012 between Liberty Utilities as Borrower and JP Morgan Chase Bank N.A. as Lender and Administrative Agent, and the other Lenders party thereto, providing for a three year, unsecured, as amended as of March 30, 2012 U.S. $100 million operating line of credit to Liberty Utilities to support the working capital and operating needs of Liberty Utilities and its subsidiaries.

(g) **National Grid Transaction Documents:** Two Stock Purchase Agreements each entered into on December 8, 2010 and amended and restated January 21, 2011 between National Grid, as seller, and Liberty Energy, as buyer. One agreement is for the purchase of all issued and outstanding shares of Granite State Electric Utility, and the other is for all the issued and outstanding shares of EnergyNorth Gas Utility. The obligations of the Buyer under each are guaranteed pursuant to a Guaranty dated as of December 8, 2010 by APUC as guarantor, in favour of National Grid. The interests of Buyer in the agreements have been transferred to Liberty Energy NH. The transactions were completed on July 3, 2012.

(h) **APCo Credit Facility:** Fifth amended and restated credit agreement between APCo, APUC, National Bank of Canada as administrative agent and certain financial institutions dated November 16, 2012 providing for a $200 million senior unsecured credit facility with a maturity date of November 16, 2015.

(i) **U.S. Debt Private Placements:** Trust Indenture dated July 2, 2012 between Liberty Utilities Finance GP1 and The Bank of New York Mellon providing for the issuance of senior unsecured debentures. First Supplemental Indenture Dated July 2, 2012 between Liberty Utilities Finance GP1, Liberty Utilities Co. and The Bank of New York Mellon in the connection with a U.S. $225 million private placement of senior notes maturing between July 31, 2017 and July 30, 2027.

(j) **U.S. $100 million Acquisition Term Facility:** Term Loan Agreement dated March 14, 2013 between Liberty Utilities and J.P. Morgan Chase Bank, N.A. providing for a U.S. $100 million term loan maturing on December 31, 2013.

13. INTERESTS OF EXPERTS

KPMG LLP is the external auditor of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation, and that they are independent accountants with respect to the Corporation under all relevant U.S. professional and regulatory standards.

14. ADDITIONAL INFORMATION

Additional information relating to APUC may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of APUC's securities and securities authorized for issuance under equity compensation plans is contained in APUC's information circular for its most recent annual meeting. Additional financial information is provided in APUC's financial statements and management discussion and analysis for the year ended December 31, 2012.

SCHEDULE A

Renewable – Hydroelectric and Wind Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2013 Power Purchase Rates(1)	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Renewable Ontario Facilities					
Facility: Long Sault Rapids Facility (Hydroelectric) **Owner**: Algonquin Power (Long Sault) Partnership and N-R Power Partnership	18,000	Abitibi River near Cochrane, Ontario	**Electricity Purchaser:** OEFC **Rates**: $0.097065/kW-hr (average estimate)	111,600	2047
Facility: Hurdman Dam Facility (Hydroelectric) **Owner**: APFC	570	Mattawa River near Mattawa, Ontario	**Electricity Purchaser:** Ontario Power Authority **Rates**: $0.08308/kW-hr Paid on Hydroelectric Contract Incentive rate	3,150	2031
Facility: Campbellford Facility (Hydroelectric) **Owner**: Campbellford LP	4,000	Trent River near Campbellford, Ontario	**Electricity Purchaser:** OEFC **Rates**: $0.04354/kW-hr (average estimate)	26,250	2019
Renewable Québec Facilities					
Facility: Saint-Alban Facility (Hydroelectric) **Owner**: SLI	8,200	Ste-Anne River near the Village of Saint-Alban, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.08075/kW-hr (Jan – Nov) $0.08317/kW-hr (Dec)	37,650	2016
Facility: Glenford Facility (Hydroelectric) **Owner**: Glenford Partnership	4,950	Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.08075/kW-hr (Jan – Nov) $0.08317/kW-hr (Dec)	24,000	2020
Facility: Rawdon Facility (Hydroelectric) **Owner**: APFC	2,500	Ouareau River near the Village of Rawdon, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.08075/kW-hr (Jan – Nov) $0.08317/kW-hr (Dec)	15,400	2014

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2013 Power Purchase Rates(1)	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Côte Ste-Catherine Facility (Hydroelectric) **Owner**: Mont-Laurier Partnership	11,120	St. Lawrence River near the Town of Ste.-Catherine, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: Phase I Energy $0.04973/kW-hr Phase II Energy $0.06889/kW-hr Capacity $169.08/kW * Phase III Energy $0.07173/kW-hr Capacity $177.28/kW* * calculated over the average kilowatt output over the period December to March	Phase 1: 15,500 Phase II: 35,100 Phase III: 34,750	Phase 1: 2021 Phase II: 2018 Phase III: 2021
Facility: Ste-Raphaël Facility (Hydroelectric) **Owner**: APFC	3,500	Rivière de Sud near Québec City, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.08075/kW-hr (Jan – Nov) $0.08317/kW-hr (Dec)	22,550	2014
Facility: Mont Laurier Facility (Hydroelectric) **Owner**: Mont-Laurier Partnership	2,725	Rivière-du-Lièvre in the Town of Mont Laurier, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.06013/kW-hr	20,000	2027
Facility : Rivière-du-Loup Facility (Hydroelectric) **Owner**: APFC	2,600	Rivière-du-Loup near the Town of Rivière-du-Loup, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.08075/kW-hr (Jan – Nov) $0.08317/kW-hr (Dec)	17,250	2015
Facility: Hydraska Facility (Hydroelectric) **Owner**: APT	2,250	Yamaska River near the Town of St.-Hyacinthe, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: Summer Energy $0.06791/kW-hr Winter Energy $0.12827/kW-hr	9,100	2014
Facility: Ste-Brigitte Facility (Hydroelectric) **Owner**: APFC	4,200	Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec	**Electricity Purchaser:** Hydro-Québec\ **Rates**: $0.08075/kW-hr (Jan – Nov) $0.08317/kW-hr (Dec)	12,750	2014

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2013 Power Purchase Rates(1)	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Belleterre Facility (Hydroelectric) **Owner**: APFC	2,200	Winneway River in the Municipality of Laforce, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: Contract under negotiation with Hydro Quebec	11,250	2013
Facility: Donnacona Facility (Hydroelectric) **Owner**: Donnacona Partnership	4,800	Jacques Cartier River near Donnacona, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.08075/kW-hr (Jan – Nov) $0.08317/kW-hr (Dec)	20,550	2022
Facility: Arthurville Facility (Hydroelectric) **Owner**: APT	650	Riviere du Sud downstream from Ste-Raphaël	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.08075/kW-hr (Jan – Nov) $0.08317/kW-hr (Dec)	0(4)	2013
Renewable New York Facilities					
Facility: Ogdensburg Facility (Hydroelectric) **Owner**: Trafalgar(2)	3,675	Oswegatchie River near Ogdensburg, New York	**Electricity Purchaser:** National Grid **Rates**: US$0.04035/kW-hr (est)(3)	11,100	2016
Facility: Forestport Facility (Hydroelectric) **Owner**: Trafalgar(2)	3,300	Black River near Boonville, New York	**Electricity Purchaser:** National Grid **Rates**: US$0.03990/kW-hr (est) (3)	11,500	2016
Facility: Herkimer Facility (Hydroelectric) **Owner**: Trafalgar(2)	1,680	West Canada Creek near Herkimer, New York	**Electricity Purchaser:** National Grid **Rates**: No target rate as the site is expected to be offline	0(4)	2016
Facility: Christine Falls Facility (Hydroelectric) **Owner**: Christine Falls Corporation(2)	850	Sacandaga River near Clifton, New York	**Electricity Purchaser:** National Grid **Rates**: US $0.04004/kW-hr (est) (3)	3,300	2028
Facility: Cranberry Lake (Hydroelectric) **Owner**: Trafalgar(2)	500	Oswegatchie River near Clifton, New York	**Electricity Purchaser:** National Grid **Rates**: US$0.04060/kW-hr (est) (3)	1,800	2016

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2013 Power Purchase Rates(1)	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Kayuta Lake Facility (Hydroelectric) **Owner**: Trafalgar[2]	400	Black River near Boonville, New York	**Electricity Purchaser:** National Grid **Rates**: US$0.00993/kW-hr (est)	1,800	2028
Facility: Adams Facility (Hydroelectric) **Owner**: Trafalgar [2]	350	Sandy Creek near Adams, New York	**Electricity Purchaser:** National Grid **Rates**: No target rate as the site is expected to be offline	0[4]	2028
Facility: Phoenix Facility [7] (Hydroelectric) **Owner**: Oswego Hydro Partners L.P.	3,500	Oswego River in Phoenix, New York	**Electricity Purchaser:** National Grid **Rates**: US$0.09205/kW-hr Flat Rate	0	2026
Facility: Beaver Falls Facility [7] (Hydroelectric) **Owner**: Algonquin Power (Beaver Falls) LLC	2,500	Beaver River in Beaver Falls, New York	**Electricity Purchaser:** National Grid **Rates**: US$0.02852/kW-hr (est)	0	2019
New England Facilities					
Facility: Greggs Falls Facility [7] (Hydroelectric) **Owner**: Greggs Falls Partnership	3,500	Piscataquog River near the Town of Goffstown, New Hampshire	**Electricity Purchaser:** Public Service Company of New Hampshire ("**PSNH**") **Rates**: US$0.05407/kW-hr (est) [5]	0	60 day written notice
Facility: Pembroke Facility[7] (Hydroelectric) **Owner**: Pembroke Hydro Associates Limited Partnership	2,600	Suncook River near the Town of Pembroke, New Hampshire	**Electricity Purchaser:** PSNH **Rates**: US$0.05461/kW-hr (est) [5]	0	60 day written notice
Facility: Clement Facility[7] (Hydroelectric) **Owner**: Clement Dam Hydroelectric LLC	2,400	Winnipisaukee River near the Town of Tilton, New Hampshire	**Electricity Purchaser:** PSNH **Rates**: US$0.05551/kW-hr (est) [5]	0	60 day written notice

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2013 Power Purchase Rates(1)	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Franklin Facility[7] (Hydroelectric) **Owner**: Franklin Power LLC	River Bend 1,600 Steven's Mill 200	Winnipesaukee River near the Town of Franklin, New Hampshire	**Electricity Purchaser:** PSNH **Rates**: River Bend US$0.05291/kW-hr (est) [5] Steven's Mill US$0.05609/kW-hr (est) [5]	River Bend 0 Steven's Mill 0	60 day written notice – both sites
Facility: Lochmere Facility[7] (Hydroelectric) **Owner**: HDI Partnership	1,200	Winnipesaukee River near Lochmere, New Hampshire	**Electricity Purchaser:** PSNH **Rates**: US$0.05560/kW-hr (est) [5]	0	60 day written notice
Facility: Lakeport Facility[7] (Hydroelectric) **Owner**: Lakeport Corporation	600	Winnipesaukee River near Laconia, New Hampshire	**Electricity Purchaser:** PSNH **Rates**: US$0.05530/kW-hr (est) [5]	0	60 day written notice
Facility: Mine Falls Facility[7] (Hydroelectric) **Owner**: Mine Falls Limited Partnership	3,000	Nashua River near the City of Nashua, New Hampshire	**Electricity Purchaser:** PSNH **Rates**: US $0.05483/kW-hr (est) [5]	0	60 day written notice
Facility: Great Falls Facility[7] (Hydroelectric) **Owner**: Great Falls Partnership	10,950	Passaic River near the City of Paterson, New Jersey	**Electricity Purchaser:** Public Service Electric and Gas Company **Rates**: US $0.05470/kW-hr (est)	0	60 day written notice
Facility: Moretown Facility[8] (Hydroelectric) **Owner**: Moretown Partnership	1,200	Mad River near Moretown, Vermont	**Electricity Purchaser:** Vermont Power Exchange, Inc. **Rates**: $0.10780/kW-hr (average estimate)	0	2018
Renewable – Western Canada Facility					
Facility: Dickson Dam Facility (Hydroelectric) **Owner:** APOT	15,000	Innisfail, Alberta	**Electricity Purchaser:** AESO **Rates**: Market Rates Energy: $0.06117/kW-hr (estimate)	65,000	NA

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2013 Power Purchase Rates(1)	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Renewable – Maritime Facilities					
Facility: Tinker Facility (Hydroelectric) **Owner**: APT	33,500	Perth-Andover, New Brunswick	**Electricity Purchaser:** AES Town of Perth-Andover **Rates:** AES ~ U.S. $0.0435/kWhr Town of Perth Andover: ~ CDN $.0825/kWhr	142,000	Perth-Andover Contract through 2021 AES contract through 2013
Facility: Caribou Facility (Hydroelectric) **Owner**: Maine Gen Co.	900	Caribou, Maine	**Electricity Purchaser:** AES **Rates**: Energy – ~U.S. $0.0435/kWhr	5,300	n/a
Facility: Squa Pan Facility (Hydroelectric) **Owner**: Maine Gen Co.	1,400	Squa Pan Lake, near Caribou Maine	**Electricity Purchaser:** AES **Rates**: Energy – ~U.S. $0.04815/kWhr	850	n/a
Facility: Rattle Brook Facility (Hydroelectric) **Owner**: Rattlebrook Partnership	4,000	Rattle Brook near Jackson's Arm, Newfoundland	**Electricity Purchaser:** Newfoundland and Labrador Hydro **Rates**: Summer $0.07148/kW-hr Winter $0.09693/kW-hr	15,950	2024
Renewable – Solar Facility					
Facility: Cornwall Solar (Solar)	10,000	Cornwall, Ontario	**Electricity Purchaser:** (Under Development – OPA)	13,400	n/a
Renewable – Wind Facilities					
Facility: Minonk	200,000	Minonk, Illinois	**Electricity Purchaser:** PJM North Illinois	674,000	2027[6]
Facility: Chaplin Wind (Wind)	177,000	Chaplin, Saskatchewan	**Electricity Purchaser:** (Under Development – SaskPower)	247,000	n/a
Facility: Senate	150,000	Graham, Texas	**Electricity Purchaser:** ERCOT North markets	520,000	2022[6]
Facility: Shady Oaks (Wind)[9]	109,500	Counties of Lee &, Brooklyn, Illinois	**Electricity Purchaser:** Commonwealth Edison	364,000	2032

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2013 Power Purchase Rates(1)	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: St. Leon Facility (Wind) **Owner**: St. Leon LP	104,000	St. Leon, Manitoba	**Electricity Purchaser:** Manitoba Hydro	372,000	2025 + one 5 year extension
Facility: Amherst Island (Wind)	75,000	Stella, Ontario	**Electricity Purchaser:** (Under Development – OPA)	247,000	n/a
Facility: Sandy Ridge (Wind)	50,000	Tyrone, Pennsylvania	**Electricity Purchaser:** PJM West	158,000	2022[6]
Facility: Red Lily (Wind) **Owner**: Concord Pacific Group	26,400	Saskatchewan	**Electricity Purchaser:** SaskPower	88,000	2036
Facility: Morse (Wind)	25,000	Morse, Saskatchewan	**Electricity Purchaser:** (Under Development – SaskPower)	93,000	n/a
Facility: Saint-Damase (Wind)	24,000	Saint-Damase, Québec	**Electricity Purchaser:** (Under Development – Hydro-Quebec)	78,000	n/a
Facility: Val-Éo (Wind)	24,000	Saint-Gédéon, Québec	**Electricity Purchaser:** (Under Development – Hydro-Quebec)	66,000	n/a
Facility: St. Leon II Facility (Wind)	16,500	St. Leon, Manitoba	**Electricity Purchaser:** Manitoba Hydro	58,000	2037

Notes:

(1) 2013 PPA rates have been rounded to four decimals and are not representative of long term power purchase rates under the applicable PPAs. Long-term rates under different agreements will be both higher and lower than current rates. Seasonal periods and daily periods vary from project to project.
(2) APC provides Trafalgar with certain operational services in respect of the Trafalgar facilities.
(3) These rates reflect the estimated Avoided Costs of National Grid.
(4) Scheduled to be offline in 2013. No decision has been made as to the timing of repairing these facilities.
(5) PSNH purchases the energy produced by these generating stations at the ISO-NE. market rates. These agreements are cancellable on 60 days written notice.
(6) Financial and physical hedges with respect to these facilities came into effect January 1, 2013.
(7) On March 14, 2013, APCo entered into an agreement to sell 10 small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of APCo.
(8) On August 31, 2012, APCo entered into an agreement to sell the Moretown hydro Facility
(9) Acquired on January 1, 2013

SCHEDULE B

Thermal – Biomass, Cogeneration, Steam, Diesel and Energy From Waste Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2013 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA	Year of Expiry of Lease
Thermal – Biomass Facility						
Facility: Valley Power Facility (Biomass) **Owner**: Valley Power L.P.	12,000	Drayton Valley, Alberta	**Electricity Purchaser:** TransAlta Utilities Corporation **Rates**: Energy: $0.0709/kW-hr	0(1)	2014	Owned
Thermal – Cogeneration Facilities						
Facility: Sanger Facility (Cogeneration) **Owner**: Algonquin Power Sanger LLC	56,000	Sanger, California	**Electricity Purchaser:** PG&E	143,300	2021	Owned
			Rates: US$ 0. 045/ kW-hr (estimated average)* * subject to gas price indexing **Capacity** – Approximately $254,800/month January-April & November-December Approximately $935,300/month May-October			
Facility: Windsor Locks Facility (Cogeneration) **Owner**: Algonquin Power Windsor Locks LLC	70,000	Windsor Locks, Connecticut	**Electricity Purchaser:** ISO New England Ahlstrom	41,000 87,000	Merchant 2018	2018
			Rates: ISO New England-Market Rates , included hourly energy, forward capacity and forward reserve payments CT Class III REC ~US$0.1/kW-hr Mill/NGC – US$0.0509/kW-hr* Capacity $207,700** Steam – DNM/NGC – US$7.54/1000lbs* Capacity $130,000 * Estimated average rate, includes variable component based on natural gas prices. ** Estimated average monthly rate, charges are CPI indexed. Capacity Market and Spot Market – market prices			
Facility: Brampton Cogeneration Inc. (Cogeneration) **Owner**: APOT	N/A	Brampton, Ontario	**Electricity Purchaser:** N/A **Rates**: Steam – Normapac $6.90/1000lbs* Capacity $104,700** * Estimated average rate, includes variable component based on natural gas prices. ** Estimated average monthly rate, charges are partially CPI indexed.	624 million lbs of steam	2024	N/A

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2013 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA	Year of Expiry of Lease
Facility: EFW Facility (Energy from Waste) **Owner**: Algonquin Power Energy from Waste Inc.	10,100	Brampton, Ontario	**Electricity Purchaser:** OEFC **Rates**: ~$0.030/kW-hr (average estimated rate)	5,600	NA	Owned
Thermal – Diesel Facilities						
Facility: Tinker Facility (Diesel) **Owner**: Tinker Gen Co.	1,000	Perth-Andover, New Brunswick	**Electricity Purchaser:** Not Under Contract **Rates**: Capacity only	0	NA	Owned
Facility: Caribou Facility (Diesel) **Owner**: Maine Gen Co.	7,000	Caribou, Maine	**Electricity Purchaser:** AES **Rates**: Capacity only	0	NA	Owned

Notes:

(1) Available to provide capacity only. The thermal facilities located in Northern Maine and New Brunswick are not considered strategic to APUC. As a result APUC is taking steps to shutdown these facilities.

SCHEDULE C

Wastewater and Water Distribution Facilities

Utility	Owner	Location	Type of Utility	December 31, 2012 Connections	Rates[1]
Black Mountain	Black Mountain Sewer Corporation	Carefree, Arizona	Wastewater	2,190	Pursuant to ACC decision 71865
Gold Canyon	Gold Canyon Sewer Company	Gold Canyon Arizona	Wastewater	7,520	Pursuant to ACC decision 69664
Bella Vista	Bella Vista Water Co., Inc.	Sierra Vista, Arizona	Water Distribution	9,220	Pursuant to ACC decision 72251
Tall Timbers	Tall Timbers Utility Company, Inc.	Tyler, Texas	Wastewater	2,200	Pursuant to TCEQ decision 2009-1381-UCR and SOAH decision 582-10-0350
Woodmark	Woodmark Utilities, Inc.	Tyler, Texas	Wastewater	1,750	Pursuant to TCEQ decision on Jan 1, 2010
Litchfield Park	Litchfield Park Service Company	Litchfield, Park, Arizona	Wastewater Water Distribution	19,490 17,540	Pursuant to ACC decision 72026
Fox River	AWRI	Sheridan, Illinois	Wastewater Water Distribution	220 220	Per customer agreement[3] US $240.08 US $141.61
Timber Creek	AWRM	DeSoto, Missouri	Wastewater Water Distribution	20 25	Pursuant to MOPSC decision WR-2006-4025
Holiday Hills	AWRM	Branson, Missouri	Water Distribution	485	Per MOPSC Case WR-2006-4025
Ozark Mountain	AWRM	Kimberling City, Missouri	Wastewater Water Distribution	240 260	Pursuant to MOPSC decision WR-2006-4025
Holly Lake Ranch	AWRT	Hawkins, Texas	Wastewater Water Distribution	150 1,940	Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369
Big Eddy	AWRT	Flint, Texas	Wastewater Water Distribution	410 680	Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369

Utility	Owner	Location	Type of Utility	December 31, 2012 Connections	Rates[1]
Piney Shores	AWRT	Conroe, Texas	Wastewater Water Distribution	270 275	Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369
Hill Country	AWRT	New Braunfels, Texas	Wastewater Water Distribution	400 230	Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369
Rio Rico	Rio Rico Utilities Inc.	Rio Rico, Arizona	Wastewater Water Distribution	2,205 6,785	Pursuant to ACC decision 72059
Northern Sunrise	Northern Sunrise Water Company Inc.	Sierra Vista, Arizona	Water Distribution	360	Pursuant to ACC decision 72251
Southern Sunrise	Southern Sunrise Water Company Inc.	Sierra Vista, Arizona	Water Distribution	870	Pursuant to ACC decision 72251
Entrada Del Oro [(2)]	Entrada Del Oro Sewer Company	Gold Canyon , Arizona	Wastewater	340	Pursuant to decision 68306
Seaside Resort	AWRT	Galveston, Texas	Water Distribution Wastewater	160 160	Per customer agreement[3] US $166.68 US $165.45
Noel	AWRM	Noel, Missouri	Water Distribution	705	Pursuant to MOPSC decision WR-2009-0395
KMB	AWRM	Jefferson, Franklin and Cape Girardeau counties in Missouri	Wastewater Water Distribution	185 545	Pursuant to MOPSC decision WO-2010-0345
Total connections				**78,050**	

Notes:

1. See www.libertyutilities.com for complete rate tariffs.
2. Liberty Water Co. currently holds a beneficial interest in the shares of the company pending regulatory approval of its acquisition.
3. Rates charged per agreement with developer

SCHEDULE D

Electrical Distribution Facilities

Utility	Owner	Location	Type of Utility	December 31, 2012 Connections / Customers	Rates[1]
California Utility	California Pacific Electric Company, LLC	Lake Tahoe, California	Electricity Distribution	Residential – 41,063 Commercial & Industrial – 7,708	Rates pursuant to CPUC decision 12-11-030
Granite State Electric Utility	Granite State Electric Company	Salem, New Hampshire	Electricity Distribution	Residential – 35,450 Commercial & Industrial – 7,800	Rates pursuant to NHPUC decision DE 13-018

Notes:

1. See www.libertyutilities.com for complete rate tariffs.

SCHEDULE E

Natural Gas Distribution Facilities[1]

Utility	Owner	Location	Type of Utility	December 31, 2010 Connections	Rates[1]
EnergyNorth Gas Utility	EnergyNorth Natural Gas, Inc.	Manchester, New Hampshire	Natural Gas Distribution	Residential – 76,350 Commercial & Industrial – 11,300	Rates pursuant to NHPUC decision DE12-265
Midstates Gas Utilities-Illinois	Liberty Energy (Midstates) Corp.	Salem, Virden, Vandalia, Xenia, Metropolis, Illinois	Natural Gas Distribution	Residential – 20,071 Commercial & Industrial – 2,073	Rates pursuant to ICC decision IL-11-0559
Midstates Gas Utilities – Iowa	Liberty Energy (Midstates) Corp.	Keokuk, Iowa	Natural Gas Distribution	Residential – 3,860 Commercial & Industrial – 468	Rates pursuant to IUB decision SPU-2011-0008

Utility	Owner	Location	Type of Utility	December 31, 2010 Connections	Rates[1]
Midstates Gas Utilities-Missouri	Liberty Energy (Midstates) Corp.	Jackson, Sikeston, Butler, Kirksville, Hannibal, Missouri	Natural Gas Distribution	Residential –48,605 Commercial & Industrial –6,687	Rates pursuant to MPSC decision GM-2012-0037

Notes:

1. See www.libertyutilities.com for complete rate tariffs.

SCHEDULE F

ALGONQUIN POWER & UTILITIES CORP.

MANDATE OF THE AUDIT COMMITTEE

By appropriate resolution of the board of directors (the " **Board**") of Algonquin Power & Utilities Corp., the Audit Committee (the " **Committee**") has been established as a standing committee of the Board with the terms of reference set forth below. Unless the context requires otherwise, the term "Corporation" refers to Algonquin Power & Utilities Corp. and its subsidiaries.

1. PURPOSE

1.1 The Committee's purpose is to:

(a) assist the Board's oversight of:

(i) the integrity of the Corporation's financial statements, Management's Discussion and Analysis (" **MD&A**") and other financial reporting;

(ii) the Corporation's compliance with legal and regulatory requirements;

(iii) the external auditor's qualifications, independence and performance;

(iv) the performance of the Corporation's internal audit function and internal auditor;

(v) the communication among management of the Corporation and its subsidiary entities and the Corporation's Chief Executive Officer and its Chief Financial Officer (collectively, "**Management**"), the external auditor, the internal auditor and the Board;

(vi) the review and approval of any related party transactions; and

(vii) any other matters as defined by the Board;

(b) prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

2. COMMITTEE MEMBERSHIP

2.1 Number of Members – The Committee shall consist of not fewer than three members.

2.2 Independence of Members – Each member of the Committee shall:

(a) be a director of the Corporation;

(b) not be an officer or employee of the Corporation or any of the Corporation's subsidiary entities or affiliates;

(c) be an unrelated director for the purposes of the Toronto Stock Exchange (the "**TSX**") Corporate Governance Policy; and

(d) satisfy the independence requirements applicable to members of audit committees under each of the rules of National Instrument 52 110 – Audit Committees of the Canadian Securities Administrators ("**NI 52 110**") and other applicable laws and regulations.

2.3 Financial Literacy – Each member of the Committee shall satisfy the financial literacy requirements applicable to members of audit committees under the TSX Corporate Governance Policy, NI 52 110 and other applicable laws and regulations.

2.4 Annual Appointment of Members – The Committee and its Chair shall be appointed annually by the Board and each member of the Committee shall serve at the pleasure of the Board until he or she resigns, is removed or ceases to be a director.

3. COMMITTEE MEETINGS

3.1 Time and Place of Meetings – The time and place of the meetings of the Committee and the calling of meetings and the procedure in all things at such meetings shall be determined by the Committee; provided, however, that the Committee shall meet at least quarterly, a majority of the members of the Committee shall constitute a quorum and the Committee shall maintain minutes or other records of its meetings and activities.

3.2 In Camera Meetings – As part of each meeting of the Committee at which it approves, or if applicable, recommends that the Board approve, the annual audited financial statements of the Corporation or at which the Committee reviews the interim financial statements of the Corporation, and at such other times as the Committee deems appropriate, the Committee shall meet separately with each of the persons set forth below to discuss and review specific issues as appropriate:

(a) representatives of Management;

(b) the external auditor; and

(c) the internal audit personnel.

3.3 Attendance at Meetings – The external auditors are entitled to attend and be heard at each Committee meeting. In addition, the Committee may invite to a meeting any officers or employees of the Corporation, legal counsel, advisor and other persons whose attendance it considers necessary or desirable in order to carry out its responsibilities.

4. COMMITTEE AUTHORITY AND RESOURCES

4.1 Direct Channels of Communication – The Committee shall have direct channels of communication with the Corporation's internal and external auditors to discuss and review specific issues as appropriate.

4.2 Retaining and Compensating Advisors – The Committee, or any member of the Committee with the approval of the Committee, may retain at the expense of the Corporation such independent legal, accounting (other than the external auditor) or other advisors on such terms as the Committee may consider appropriate and shall not be required to obtain any other approval in order to retain or compensate any such advisors.

4.3 Funding – The Corporation shall provide for appropriate funding, as determined by the Committee, for payment of compensation of the external auditor and any advisor retained by the Committee under Section 4.2 of this Charter.

4.4 Investigations – The Committee shall have unrestricted access to the personnel and documents of the Corporation and the Corporation's subsidiary entities and shall be provided with the resources necessary to carry out its responsibilities.

5. REMUNERATION OF COMMITTEE MEMBERS

5.1 Director Fees Only – No member of the Committee may accept, directly or indirectly, fees from the Corporation or any of its subsidiary entities other than remuneration for acting as a director or member of the Committee or any other committee of the Board.

5.2 Other Payments – For greater certainty, no member of the Committee shall accept any consulting, advisory or other compensatory fee from the Corporation. For purposes of Section 5.1, the indirect acceptance by a member of the Committee of any fee includes acceptance of a fee by an immediate family member or a partner, member or executive officer of, or a person who occupies a similar position with, an entity that provides accounting, consulting, legal, investment banking or financial advisory services to the Corporation or any of its subsidiaries, other than limited partners, non–managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity.

6. DUTIES AND RESPONSIBILITIES OF THE COMMITTEE

6.1 Overview – The Committee's principal responsibility is one of oversight. Management is responsible for preparing the Corporation's financial statements and the external auditor is responsible for auditing those financial statements.

6.2 The Committee's specific duties and responsibilities are as follows:

(a) Financial and Related Information

(i) Annual Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's annual financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(ii) Interim Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's interim financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(iii) Prospectuses and Other Documents – The Committee shall review and discuss with Management and the external auditor the financial information, financial statements and related MD&A appearing in any prospectus, annual report, annual information form, management information circular or any other public disclosure document prior to its public release or filing and if applicable, report thereon to the Board as a whole.

(iv) Accounting Treatment – Prior to the completion of the annual external audit, and at any other time deemed advisable by the Committee, the Committee shall review and discuss with Management and the external auditor (and shall arrange for the documentation of such discussions in a manner it deems appropriate) the quality and not just the acceptability of the Corporation's accounting principles and financial statement presentation, including, without limitation, the following:

(A) all critical accounting policies and practices to be used, including, without limitation, the reasons why certain estimates or policies are or are not considered critical and how current and anticipated future events impact those determinations and an assessment of Management's disclosures along with any significant proposed modifications by the auditors that were not included;

(B) all alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with Management, including, without limitation, ramification of the use of such alternative disclosure and treatments, and the treatment preferred by the external auditor, which discussion should address recognition, measurement and disclosure consideration related to the accounting for specific transactions as well as general accounting policies. Communications regarding specific transactions should identify the underlying facts, financial statement accounts impacted and applicability of existing corporate accounting policies to the transaction. Communications regarding general accounting policies should focus on the initial selection of, and changes in, significant accounting policies, the impact of the Management's judgments and accounting estimates and the external auditor's judgments about the quality of the Corporation's accounting principles. Communications regarding specific transactions and general accounting policies should include the range of alternatives available under generally accepted accounting principles discussed by Management and the auditors and the reasons for selecting the chosen treatment or policy. If the external auditor's preferred accounting treatment or accounting policy is not selected, the reasons therefore should also be reported to the Committee;

(C) other material written communications between the external auditor and Management, such as any management letter, schedule of unadjusted differences, listing of adjustments and reclassifications not recorded, management representation letter, report on observations and recommendations on internal controls, engagement letter and independence letter;

(D) major issues regarding financial statement presentations;

(E) any significant changes in the Corporation's selection or application of accounting principles;

(F) the effect of regulatory and accounting initiatives, as well as off balance sheet structures, on the financial statements of the Corporation; and

(G) the adequacy of the Corporation's internal controls and any special audit steps adopted in light of control deficiencies.

(v) Disclosure of Other Financial Information – The Committee shall:

(A) review, and discuss generally with Management, the type and presentation of information to be included in, all public disclosure by the Corporation containing audited, unaudited or forward-looking financial information in advance of its public release by the Corporation, including, without limitation, earnings guidance and financial information based on unreleased financial statements;

(B) discuss generally with Management the type and presentation of information to be included in earnings and any other financial information given to analysts and rating agencies, if any; and

(C) satisfy itself that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, other than the Corporation's financial statements, MD&A and earnings press releases, and shall periodically assess the adequacy of those procedures.

(b) External Auditor

(i) Authority with Respect to External Auditor – As representative of the Corporation's shareholders and as a committee of the Board, the Committee shall be directly responsible for the appointment, compensation, retention, termination and oversight of the work of the external auditor (including, without limitation, resolution of disagreements between Management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation. In this capacity, the Committee shall have sole authority for recommending the person to be proposed to the Corporation's shareholders for appointment as external auditor, whether at any time the incumbent external auditor should be removed from office, and the compensation of the external auditor. The Committee shall require the external auditor to confirm in an engagement letter to the Committee each year that the external auditor is accountable to the Board and the Committee as representatives of shareholders and that it will report directly to the Committee.

(ii) Approval of Audit Plan – The Committee shall approve, prior to the external auditor's audit, the external auditor's audit plan (including, without limitation, staffing), the scope of the external auditor's review and all related fees.

(iii) Independence – The Committee shall satisfy itself as to the independence of the external auditor. As part of this process:

(A) The Committee shall require the external auditor to submit on a periodic basis to the Committee a formal written statement confirming its independence under applicable laws and regulations and delineating all relationships between the auditor and the Corporation and the Committee shall actively engage in a dialogue with the external auditor with respect to any disclosed relationships or services that may impact the objectivity and independence of the external auditor and take, or, if applicable, recommend that the Board take, any action the Committee considers appropriate in response to such report to satisfy itself of the external auditor's independence.

(B) In accordance with applicable laws and regulations, the Committee shall pre–approve any non–audit services (including, without limitation, fees therefore) provided to the Corporation or its subsidiaries by the external auditor or any auditor of any such subsidiary and shall consider whether these services are compatible with the external auditor's independence, including, without limitation, the nature and scope of the specific non–audit services to be performed and whether the audit process would require the external auditor to review any advice rendered by the external auditor in connection with the provision of non-audit services. The Chair may approve additional non audit services that arise between Committee meetings, provided that the Chair reports any such approvals to the Committee at the next scheduled meeting.

(C) The Committee shall establish a policy setting out the restrictions on the Corporation's subsidiary entities hiring partners, employees, former partners and former employees of the Corporation's external auditor or former external auditor.

(iv) Rotating of Auditor Partner – The Committee shall evaluate the performance of the external auditor and whether it is appropriate to adopt a policy of rotating lead or responsible partners of the external auditors.

(v) Review of Audit Problems and Internal Audit – The Committee shall review with the external auditor:

(A) any problems or difficulties the external auditor may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any disagreements with Management and any management letter provided by the auditor and the Corporation's response to that letter;

(B) any changes required in the planned scope of the internal audit; and

(C) the internal audit department's responsibilities, budget and staffing.

(vi) Review of Proposed Audit and Accounting Changes – The Committee shall review major changes to the Corporation's auditing and accounting principles and practices suggested by the external auditor.

(vii) Regulatory Matters – The Committee shall discuss with the external auditor the matters required to be discussed by CAS 260 of the CICA Handbook – Assurance relating to the conduct of the audit.

(c) Internal Audit Function – Controls

(i) Regular Reporting – Internal audit personnel shall report regularly to the Committee.

(ii) Oversight of Internal Controls – The Committee shall oversee Management's design and implementation of and reporting on the Corporation's internal controls and review the adequacy and effectiveness of Management's financial information systems and internal controls. The Committee shall periodically review and approve the mandate, plan, budget and staffing of internal audit personnel. The Committee shall direct Management to make any changes it deems devisable in respect of the internal audit function.

(iii) Review of Audit Problems – The Committee shall review with the internal audit personnel: any problem or difficulties the internal audit personnel may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any significant reports to Management prepared by the internal audit personnel and Management's responses thereto.

(iv) Review of Internal Audit Personnel – The Committee shall review the appointment, performance and replacement of the senior internal auditing personnel and the activities, organization structure and qualifications of the persons responsible for the internal audit function.

(d) Risk Assessment and Risk Management

(i) Risk Exposure – The Committee shall discuss with the external auditor, internal audit personnel and Management periodically the Corporation's major financial risk exposures and the steps Management has taken to monitor and control such exposures.

(ii) Investment Practices – The Committee shall review Management's plans and strategies around investment practices, banking performance and treasury risk management.

(iii) Compliance with Covenants – The Committee shall review Management's procedures to ensure compliance by the Corporation with its loan covenants and restrictions, if any.

(e) Legal Compliance

(i) On at least a quarterly basis, the Committee shall review with the Corporation's legal counsel, external auditor and Management any legal matters (including, without limitation, litigation, regulatory investigations and inquiries, changes to applicable laws and regulations, complaints or published reports) that could have a significant impact on the Corporation's financial position, operating results or financial statements and the Corporation's compliance with applicable laws and regulations.

(ii) The Committee shall review and, if applicable, advise the Board with respect to the Corporation's policies and procedures regarding compliance with applicable laws and regulations and shall notify Management and, if applicable, the Board, promptly after becoming aware of any material non–compliance by the Corporation with applicable laws and regulations.

(f) Whistle Blowing – The Committee shall establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation's subsidiary entities of concerns regarding questionable accounting or auditing matters.

(g) Related Party Transactions – The Committee shall review and approve any transaction between the Corporation and a related party and any transaction involving the Corporation and another party in which the parties' relationship could enable the negotiation of terms on other than an independent, arms' length basis.

(h) Review of the Management's Certifications and Reports – The Committee shall review and discuss with Management all certifications of financial information, management reports on internal controls and all other management certifications and reports relating to the Corporation's financial position or operations required to be filed or released under applicable laws and regulations prior to the filing or release of such certifications or reports.

(i) Liaison – The Committee shall review and ensure that appropriate liaison and co–operation exist between the external auditor and internal audit personnel and provide a direct channel of communication between external and internal auditors and the Committee.

(j) Public Reports – The Committee shall prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

(k) Other Matters – The Committee may, in addition to the foregoing, perform such other functions as may be necessary or appropriate for the performance of its oversight function.

7. REPORTING TO THE BOARD

7.1 Regular Reporting – If applicable, the Committee shall report to the Board following each meeting of the Committee and at such other times as the Committee may determine to be appropriate.

8. EVALUATION OF COMMITTEE PERFORMANCE

8.1 Performance Review – The Committee shall periodically assess its performance.

8.2 Amendments to Charter

(a) Review by Committee – On at least an annual basis, the Committee shall review and discuss the adequacy of this Charter and if applicable, recommend any proposed changes to the Board.

(b) Review by Board – The Board will review and reassess the adequacy of the Charter on an annual basis and at such other times, as it considers appropriate.

9. LEGISLATIVE AND REGULATORY CHANGES

9.1 Compliance – It is the Board' intention that this mandate shall reflect at all times all legislative and regulatory requirements applicable to the Committee. Accordingly, this Charter shall be deemed to have been updated to reflect any amendments to such legislative and regulatory requirements and shall be formally amended at least annually to reflect such amendments.

10. CURRENCY OF CHARTER

10.1 Currency of Charter – This Charter was approved by the Board of Directors of Algonquin Power & Utilities Corp. effective March 31, 2010.

SCHEDULE G

GLOSSARY OF TERMS

In this Annual Information Form, the following terms have the meanings set forth below, unless otherwise indicated.

"**2011 APCo Debentures**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2011 – APCo – Power Generation – APCo Senior Unsecured Debentures".*

"**2012 APCo Debentures**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – APCo – Power Generation – APCo $150 million Senior Unsecured Debentures".*

"**3793257**" means 3793257 Canada Inc., a corporation incorporated under the CBCA. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**AAP LP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**ACC**" means the Arizona Corporate Commission. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater – Principal Markets – Arizona".*

"**ADEQ**" means the Arizona Department of Environmental Quality. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater – Principal Markets – Arizona".*

"**AES**" means Algonquin Energy Services Inc., a Delaware corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**AESO**" means the Alberta Electric System Operator. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Principal Markets and Distribution Methods – Alberta".*

"**Agreement**" has the meaning ascribed thereto under "*Description of the Business – Business Associations with APMI and Senior Executives"* .

"**AirSource**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**AirSource Senior Debt**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2011 – APCo – Power Generation – APCo Senior Unsecured Debentures".*

"**Algonquin Holdco**" means Algonquin Power Fund (America) Holdco Inc., a Delaware corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APA**" means Algonquin Power (America) Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**APC**" means Algonquin Power Corporation Inc. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Material Facilities – Long Sault Rapids Facility".*

"**APCo**" means Algonquin Power Co. See *"Corporate Structure – Name, Address and Incorporation"*.

"**APCo Credit Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2010 – Liberty Utilities – Liberty Utilities (West) – Senior Debt Financing".*

"**APEFW**" means Algonquin Power Energy From Waste Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APFA**" means Algonquin Power Fund (America) Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APFC**" means Algonquin Power Fund (Canada) Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APMI**" means Algonquin Power Management Inc., a corporation in which the Senior Executives have an interest.

"**APOT**" means Algonquin Power Operating Trust. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APT**" means Algonquin Power Trust. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APUC**" or the "**Corporation**" means Algonquin Power & Utilities Corp including, for reporting purposes only, the direct or indirect subsidiary entities of APUC and partnership interests held by APUC and its subsidiaries. See *"Corporate Structure – Name, Address and Incorporation"*.

"**APUC Businesses**" means the two businesses through which APUC primarily conducts its operations: independent power generation and utilities (water, natural gas and electric). See *"General Development of the Business – General – Business Strategy".*

"**APUC Credit Facility**" means the $30.0 million unsecured revolving credit facility of APUC. See " *General Development of the Business – Three Year History and Significant Acquisitions – Recent Developments – Fiscal 2012 – Corporate – APUC Credit Facility".*

"**Atmos**" means ATMOS Energy Corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Audit Committee**" means APUC's audit committee. See *"Directors and Officers – Audit Committee – Audit Committee Charter".*

"**Avoided Costs**" means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes – United States".*

"**BCI**" means Brampton Cogeneration Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**BCI Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Belle Rivière**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Blackout Period**" has the meaning ascribed thereto "*Description of Capital Structure – Stock Option Plan*".

"**Board**" means the APUC Board of Directors.

"**By-Laws**" means the by-laws of APUC. See "*Directors and Officers – Name, Occupation and Security Holdings* ".

"**California Utility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Calpeco**" means California Pacific Electric Company, LLC, a California limited liability company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Campbellford Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Campbellford LP**" means Algonquin Power (Campbellford) Limited Partnership. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Caribou Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2010 – APCo – Power Generation – Tinker Facility"*.

"**CBCA**" means the *Canada Business Corporations Act*.

"**CC**" means Compensation Committee. See *"Directors and Officers – Corporate Governance and Compensation Committees"*.

"**CC&N**" means a certificate of convenience and necessity. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Water Utility Services Regulatory Regimes"*.

"**CDP**" means the Carbon Disclosure Project. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**CGC**" means Corporate Governance Committee. See *"Directors and Officers – Corporate Governance and Compensation Committees"*.

"**Chapais**" means Chapais Energie, Société en Commandité. See *"Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments"*.

"**Clarica**" means The Clarica Life Insurance Company. *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Material Facilities – Long Sault Rapids Facility".*

"**CL&P**" means the Connecticut Light and Power Company. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration – Principal Markets and Distribution Methods – Connecticut".*

"**Cochrane**" means Cochrane Power Corporation. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration – Material Facilities – Cochrane Facility".*

"**COD**" means commercial operation dates. See *"General Development of the Business – Recent Developments – 2012".*

"**ComFIT**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – APCo: Development Division – Principal Market Environment"*.

"**Common Shares**" means the common shares of APUC created pursuant to a certificate and articles of arrangement dated October 27, 2009. See *"Corporate Structure – Name, Address and Incorporation"* .

"**Cornwall Solar**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – APCo: Development Division – Current Development Projects – Cornwall Solar".*

"**Cornwall Solar**" means Cornwall Solar Inc. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – APCo: Development Division – Current Development Projects – Cornwall Solar"*.

"**Corporation**" means APUC.

"**Corporation St-Laurent**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Court Street**" means Court Street Investments, Inc., a Massachusetts corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Co-Owners**" means Algonquin Power (Long Sault) Partnership and N-R Power Partnership as co-owners of the Long Sault Rapids Facility. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Material Facilities – Long Sault Rapids Facility".*

"**CPUC**" means the California Public Utilities Commission. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Liberty Utilities: Electrical Distribution – Principal Markets – California".*

"**CPUV**" means California Pacific Utilities Ventures, LLC, a California limited liability company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**DEP**" means the US Department of Energy. See " *Description of the Business – Competitive Conditions – APCo – Power Generation* ".

"**DSU**" means deferred share units. See "*Description of Capital Structure – Directors Deferred Share Units* ".

"**Dickson Dam Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**ECAC**" means the Energy Cost Adjustment Clause. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Liberty Utilities: Electrical Distribution – Principal Markets – California".*

"**EFW Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Electricity Act**" means the *Electricity Act* (New Brunswick). See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Principal Markets and Distribution Methods – New Brunswick and Northern Maine".*

"**Eligible Individual**" has the meaning ascribed thereto "*Description of Capital Structure – Stock Option Plan*".

"**Eligible Persons**" has the meaning ascribed thereto "*Description of Capital Structure – Stock Option Plan*".

"**EnergyNorth Gas Utility**" means EnergyNorth Natural Gas Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"* .

"**Entrada**" means Entrada Del Oro Sewer Company, Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"* .

"**Éoliennes**" means Corporation D'Investissements Éoliennes Algonquin Power. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**EPA**" means the Environmental Protection Agency. See *"Risk Factors – Operational Risk Management – Environmental Risks".*

"**ERCOT**" means Electricity Reliability Council of Texas. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Wind Power – Principal Markets and Distribution Methods"*

"**ERs**" means the Final Essential Requirements for Mandatory Reporting. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks".*

"**ESA**" means energy services agreement. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2011 – APCo – Power Generation – Windsor Locks Repowering".*

"**ESPP**" means employee share purchase plan. See "*Description of Capital Structure – Employee Share Purchase Plan* ".

"**EUA**" means the *Electric Utilities Act* (Alberta). See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Principal Markets and Distribution Methods – Alberta".*

"**FERC**" means the United States Federal Energy Regulatory Commission. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes – United States".*

"**FIT**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – APCo: Development Division – Principal Market Environment".*

"**FPA**" means the U.S. Federal Power Act. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes – United States".*

"**Gamesa USA**" means Gamesa Energy USA, LLC. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – APCo – Power Generation – Acquisition of U.S. Wind Facilities".*

"**Gamesa Wind Facilities** " has the meaning ascribed thereto under " *General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Corporate – Issuance of $120M Preferred Shares".*

"**Georgia Utility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Liberty Utilities – Agreement to Acquire Georgia Utility".*

"**gpd**" means gallons per day. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater – Material Facilities – Gold Canyon Facility".*

"**Goldwind**" has the meaning ascribed thereto under " *General Development of the Business – Three Year History and Significant Acquisitions – Recent Developments – 2013 – APCo – Power Generation – Acquisition of Shady Oaks Wind Facility".*

"**Granite State Electric Utility**" means Granite State Electric Company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Green Power**" means electricity generated from renewable energy sources that do not contribute to greenhouse gas emissions. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes – Canada".*

"**HOEP**" means Hourly Ontario Energy Price. See " *Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Energy From Waste – Material Facilities – EFW Facility".*

"**In-the-Money Amount**" has the meaning ascribed thereto "*Description of Capital Structure – Stock Option Plan*".

"**ISO-NE**" means Independent System Operator New England. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration – Principal Markets and Distribution Methods – Connecticut".*

"**ITC**" means investment tax credit. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – APCo: Development Division – Principal Market Environment*".

"**Kineticor**" has the meaning ascribed thereto *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – APCo: Development Division – Current Development Projects – Morse Wind Project".*

"**Kirkland**" means Kirkland Lake Power Corp. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration – Material Facilities – Kirkland Facility".*

"**Laclede**" has the meaning ascribed thereto under "*General Development of the Business – Three Year History and Significant Acquisitions – Recent Developments – 2013 – Liberty Utilities – Agreement to Acquire New England Utility".*

"**Liberty Credit Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Liberty Utilities – Expansion of Liberty Credit Facility".*

"**Liberty Energy**" means Liberty Energy Utilities Co. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Liberty Energy (NH)**" means Liberty Energy Utilities (New Hampshire) Corp., a Delaware corporation registered in New Hampshire. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Liberty Georgia**" means Liberty Energy (Georgia) Corp., a Georgia corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Liberty Midstates**" means Liberty Energy (Midstates) Corp., a Missouri corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Liberty Utilities**" means Liberty Utilities Company. See *"Corporate Structure – Name, Address and Incorporation"*.

"**Liberty Water**" means Liberty Water Co., a Delaware company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Loyalist LP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**LSR Royalty Interest**" means a royalty in the form of cash flows generated by the Long Sault Rapids Facility. See *"Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments"*.

"**LSR Subordinate Note**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments"*.

"**LU GP1**" means Liberty Utilities Finance GP 1, a special purpose financing company and a Delaware general partnership. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**LU GP2**" means Liberty Utilities Finance GP 2, a special purpose financing company and a Delaware general partnership. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Manitoba Hydro**" means the Manitoba Hydro-Electric Board.

"**Market Price**" has the meaning ascribed thereto "*Description of Capital Structure – Stock Option Plan*".

"**Market Purchase**" means Common Shares purchased on the open market through the facilities of the TSX. See *"Dividends – Dividend Reinvestment Plan."*

"**Meeting**" means the annual general meeting of shareholders of APUC held on June 23, 2010.

"**Merger**" has the meaning ascribed thereto "*Description of Capital Structure – Stock Option Plan*".

"**MGP**" means manufactured gas plants. See *"Risk Factors – Operational Risk Management – Environmental Risks"*.

"**Midwest Gas Utilities**" means certain natural gas distribution utility assets located in Missouri, Iowa, and Illinois. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Liberty Utilities – Acquisition of Missouri Utility"*.

"**MIPA**" means Membership Interest Purchase and Sale Agreement. See *"Material Contracts"*.

"**Mont-Laurier Partnership**" means Algonquin Power (Mont-Laurier) Limited Partnership. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**MPS**" means Maine Public Service Company. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2011 – APCo – Power Generation – AES Standard Offer Contract"*.

"**MW**" means megawatt.

"**National Grid**" means National Grid USA. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**NB Power**" means New Brunswick Power Corporation. *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Principal Markets and Distribution Methods – New Brunswick and Northern Maine"*.

"**NBSO**" means New Brunswick System Operator. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Principal Markets and Distribution Methods – New Brunswick and Northern Maine".*

"**NEGasCo Acquisition**" has the meaning ascribed thereto under "*General Development of the Business – Three Year History and Significant Acquisitions – Recent Developments – 2013 – Liberty Utilities – Agreement to Acquire New England Utility".*

"**NHPUC**" means New Hampshire Public Utilities Commission. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Liberty Utilities – AAcquisition of New Hampshire Utility".*

"**Northern Maine Gen Co.**" means Algonquin Northern Maine Gen Co., a Wisconsin company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Northland**" means Northland Power Inc. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration – Material Facilities – Kirkland Facility".*

"**NTP**" means Notice to Proceed. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – APCo: Development Division – Current Development Projects – Amherst Island Wind".*

"**OATT**" means open access transmission tariff. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes – United States".*

"**OEB**" means the Ontario Energy Board.

"**OEFC**" means Ontario Electric Financial Corporation.

"**Offering**" means a public offering completed by APUC on October 27, 2011 of 15,100,000 common shares at a price of $5.65 per share, for gross proceeds of approximately $85.3 million. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2011 – Corporate – Strengthened Liquidity – Issuance of $95.3 million of Common Shares".*

"**Off-peak**" means the hours other than On-peak hours. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Material Facilities – Long Sault Rapids Facility".*

"**On-peak**" means between 7:00 a.m. and 11:00 p.m., local time, Monday to Friday, inclusive, but excluding public holidays. *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Material Facilities – Long Sault Rapids Facility".*

"**Optionee**" has the meaning ascribed thereto "*Description of Capital Structure – Stock Option Plan*".

"**Options**" has the meaning ascribed thereto "*Description of Capital Structure – Stock Option Plan*".

"**Parties**" has the meaning ascribed thereto under "*Description of the Business – Business Associations with APMI and Senior Executives*" .

"**Peel**" means the Regional Municipality of Peel, Ontario.

"**PG&E**" means Pacific Gas & Electric Company. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration – Material Facilities – Sanger Facility".*

"**PHMSA**" means the Pipeline Hazardous Material Safety Administration. See *"Risk Factors – Operational Risk Management – Environmental Risks".*

"**Pine Bluff Water Utility**" has the meaning ascribed thereto under "*General Development of the Business – Three Year History and Significant Acquisitions – Recent Developments – 2013 – Liberty Utilities – Acquisition of Arkansas Utility".*

"**PJM**" means PJM Interconnection. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Wind Power – Principal Markets and Distribution Methods"*

"**Plan Shares**" has the meaning ascribed thereto under *"Dividends – Dividend Reinvestment Plan."*

"**Power Pool**" means the Power Pool of Alberta. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Principal Markets and Distribution Methods – Alberta".*

"**Power Sales Contracts**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – APCo – Power Generation – Acquisition of U.S. Wind Facilities".*

"**PPAs**" means long term power purchase agreements. See *"General Development of the Business – General – Business Strategy".*

"**PSC**" means the Arkansas Public Service Commission. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater – Principal Markets – Arkansas".*

"**PSU**" means performance share units. See "*Description of Capital Structure – Performance Share Units*".

"**PTAM**" means the Post Test Year Adjustment Mechanism. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Liberty Utilities: Electrical Distribution – Principal Markets – California".*

"**PTC**" means production tax credit. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – APCo: Development Division – Principal Market Environment"*.

"**Purchase Agreement**" means the asset purchase agreement by and between Sierra Pacific Power Company d/b/a NV Energy and Calpeco dated April 22, 2009 in relation to the California Utility. See *"General Development of the Business – Three Year History – Fiscal 2010"*.

"**PURPA**" means the Public Utilities Regulatory Policies Act. "See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes – United States"*.

"**QFs**" means Qualifying Facilities. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes – United States"*.

"**QF Status**" means Qualifying Facility status. See *"Risk Factors – Regulatory Climate and Permitting Risks – APCo"*.

"**Red Lily I**" means a 26.4 MW wind generation facility in southeastern Saskatchewan. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Wind Power – Material Facilities – Red Lily Wind Facility"*.

"**Reinvestment Plan**" has the meaning ascribed thereto under *"Dividends – Dividend Reinvestment Plan."*

"**RGGI**" means the Regional Greenhouse Gas Initiative. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**Rights Plan**" means APUC's Shareholders' Rights Plan adopted at the Meeting. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2010 – Corporate"*.

"**RTO**" means regioanl transmission organizations. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Wind Power – Principal Markets and Distribution Methods"*

"**run of the river**" means a facility where there is a continuous discharge of water without storage and release of water. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Material Facilities – Long Sault Rapids Facility"*.

"**S&P**" means Standard and Poor's. See "*General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Corporate – Issuance of $120M Preferred Shares"*.

"**SaskPower**" means Saskatchewan Power Corporation.

"**Sanger LLC**" means Algonquin Power Sanger LLC, a California limited liability company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Seaway Management**" means The St. Lawrence Seaway Management Corporation. See *"Risk Factors – Operational Risk Management – Litigation risks and other contingencies"*.

"**S.E.N.C.**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Senior Executives**" means two executives of APUC, Ian Robertson and Christopher Jarratt. See *"General Development of the Business – Three Year History and Significant Acquisitions – Recent Developments – 2013 – Corporate – Agreement with St. Leon Class B unit holders".*

"**Series A Shares**" means the cumulative rate reset preferred shares, Series A, of APUC. See " *General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Corporate – Issuance of $120M Preferred Shares".*

"**Series 1A Debentures**" means the 7.50% convertible unsecured subordinated debentures due November 30, 2014. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2011 – Corporate – Strengthened Balance Sheet – Conversion of Convertible Debentures to Equity".*

"**Series 1A Redemption Date**" means May 16, 2011. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2011 – Corporate – Strengthened Balance Sheet – Conversion of Convertible Debentures to Equity".*

"**Series 2A Debentures**" means APUC's 6.35% convertible unsecured subordinated debentures due November 30, 2016. See " *General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Corporate – Conversion of Series 2A Convertible Debentures to Equity".*

"**Series 2A Redemption Date**" means February 24, 2012. See "*General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Corporate – Conversion of Series 2A Convertible Debentures to Equity".*

"**Series 3 Debentures**" means the 7% convertible unsecured subordinated debentures due June 30, 2017. See " *General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Corporate – Conversion and Redemption of Series 3 Convertible Debentures to Equity".*

"**Series 3 Redemption Date**" means January 1, 2013. See "*General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Corporate – Conversion and Redemption of Series 3 Convertible Debentures to Equity".*

"**Share Reorganization**" has the meaning ascribed thereto "*Description of Capital Structure – Stock Option Plan*".

"**Shareholders**" means registered holders of shares of APUC.

"**SOP**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – APCo: Development Division – Principal Market Environment"*.

"**SponsorCo**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Squa Pan Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2010 – APCo – Power Generation – Tinker Facility".*

"**St Damase LP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**St. Leon Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**St. Leon II**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**St. Leon II Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**St. Leon GP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**St. Leon LP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**St. Leon Trust**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**St. Ulrich LP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Stock Option Plan**" means APUC's stock option Plan. See "*Description of Capital Structure – Stock Option Plan*".

"**Strategic Investment Agreement**" means the strategic investment agreement between APUC and Emera entered into on April 29, 2011. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2011 – Corporate – Strategic Investment Agreement with Emera".*

"**Successor Corporation**" has the meaning ascribed thereto "*Description of Capital Structure – Stock Option Plan*".

"**TCE**" means trichloroethylene. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**TCEQ**" means the Texas Commission on Environmental Quality. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater – Principal Markets – Texas".*

"**Tinker Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2010 – APCo – Power Generation – Tinker Facility".*

"**Tinker Assets**" means the 36.8MW of electrical generating assets of Tinker Gen Co. in New Brunswick. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Tinker Gen Co.**" means Algonquin Tinker Gen Co., a Wisconsin company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**TMO**" means Transition Management Office. See *"Risk Factors – Acquisitions and Divestitures"*.

"**Trafalgar**" has the meaning ascribed thereto under "*Description of the Business – Business Associations with APMI and Senior Executives"* .

"**Treasury Purchase**" means newly issued Plan Shares purchased from APUC under the Reinvestment Plan. See *"Dividends – Dividend Reinvestment Plan".*

"**Trust Units**" has the meaning ascribed thereto under *"Corporate Structure – Name, Address and Incorporation"*.

"**Unit Exchange**" has the meaning ascribed thereto under *"General Development of the Business – General – The Unit Exchange".*

"**Valley Power Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Vestas**" means Vestas-Canadian Wind Technology, Inc. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Wind Power – Material Facilities – St. Leon Facility".*

"**Water Services**" means Algonquin Water Services LLC. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Windlectric**" means Windlectric Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Windsor LLC**" means Algonquin Power Windsor Locks LLC, a Connecticut limited liability company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**WE HoldCo**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**WP HoldCo**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**WPPI**" means Wind Power Production Incentive See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Wind Power – Material Facilities – St. Leon Facility".*

"**Yankee Gas**" means the Yankee Gas Service Company. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration – Material Facilities – Windsor Locks Facility"*.

Exhibit 99.2

Consolidated Financial Statements of
Algonquin Power & Utilities Corp.
For the years ended December 31, 2012 and 2011

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, 2012, based on the framework established in *Internal Control – Integrated Framework* 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 at December 31, 2012.

During the year ended December 31, 2012, APUC acquired Granite State Electric Company, EnergyNorth Natural Gas Inc., Liberty Energy (Midstates) Corp. and Wind Portfolio SponsorCo LLC associated with total assets of $757.7 million and total revenues of $117.0 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2012. As permitted by National Instrument 52-109 and the U.S. Securities and Exchange Commission, Management excluded these acquisitions from its evaluation of the effectiveness of the Company's internal controls over financial reporting as of December 31, 2012 due to the complexity associated with assessing internal controls during integration efforts and the proximity of certain of the acquisitions to year-end.

March 14, 2013

/s/ Ian Robertson
Chief Executive Officer

/s/ David Bronicheski
Chief Financial Officer

KPMG LLP
Chartered Accountants
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Algonquin Power & Utilities Corp.

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

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

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

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

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 14, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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

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

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

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



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

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

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

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 14, 2013

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

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

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

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

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)

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

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income (Loss)

(thousands of Canadian dollars)

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

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity
(thousands of Canadian dollars)

For the year ended December 31, 2012:

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

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity
(thousands of Canadian dollars)

For the year ended December 31, 2011:

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

See accompanying notes to interim consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of Canadian dollars)

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

See accompanying notes to consolidated financial statements

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

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

1. Significant accounting policies

(a) Basis of preparation:

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

(b) Basis of consolidation:

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

(c) Accounting for rate regulated operations:

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

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

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

(d) Cash and cash equivalents:

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

1. Significant accounting policies (continued)

(e) Restricted cash:

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

(f) Accounts receivable

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

(g) Gas in storage

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

(h) Supplies and consumables inventory

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

(i) Property, plant and equipment:

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

1. Significant accounting policies (continued)

(i) Property, plant and equipment (continued):

AFUDC represents the cost of borrowed funds (allowance for borrowed funds used during construction) and a return on other funds (allowance for equity funds used during construction). 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. The interest capitalized that relates to debt reduces interest expense on the Consolidated Statement of Operations. The AFUDC capitalized that relates to equity funds is recorded as interest, dividend and other income on the Consolidated Statement of Operations.

	2012	2011
Interest capitalized on non-regulated property	$1,036	$ 87
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	628	155
Allowance for equity funds	1,108	236
Total	$2,772	$478

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

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 range of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2012	2011	2012	2011
Generation				
Renewable	3 – 60	3 – 60	32	31
Thermal	3 – 40	3 – 40	23	22
Distribution				
Gas	5 – 80	N/A	38	N/A
Electrical	8 – 75	15 – 75	42	52
Water & wastewater	5 – 50	5 – 50	25	25
Equipment	5 – 50	5 – 50	21	24

1. Significant accounting policies (continued)

(i) Property, plant and equipment (continued):

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

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

(j) Intangibles:

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

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

(k) Goodwill:

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

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

1. Significant accounting policies (continued)

(l) Impairment of long-lived assets:

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

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

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

(m) Variable interest entities:

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

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

(n) Long-term investments and notes receivable:

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

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

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

1. Significant accounting policies (continued)

(o) Advances in aid of construction:

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

(p) Deferred water rights and customer deposits:

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

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

(q) Pension and other post employment plans:

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

1. Significant accounting policies (continued)

(r) Asset retirement obligations:

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

(s) Stock based compensation

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

(t) Noncontrolling interests:

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

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

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

1. Significant accounting policies (continued)

(u) Recognition of revenue:

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

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

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

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

Interest from long-term investments is recorded as earned.

(v) Foreign currency translation:

The Company's reporting currency is the Canadian dollar.

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

1. Significant accounting policies (continued)

(w) Income taxes:

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

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

(x) Financial instruments and derivatives:

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

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

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

1. Significant accounting policies (continued)

(x) Financial instruments and derivatives (continued)

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

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

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

(y) Fair value measurements

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

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

1. Significant accounting policies (continued)

(z) Commitments and contingencies

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

(aa) Use of estimates

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

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

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

(b) Recent accounting guidance not yet adopted

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

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

3. Business acquisitions and development projects

(a) Acquisition of New Hampshire electric and gas utilities

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

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

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

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

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

3. Business acquisitions and development projects (continued)

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

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

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

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

(b) Acquisition of Midwest Gas Utilities

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

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

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

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

3. Business acquisitions and development projects (continued)

(b) Acquisition of Midwest Gas Utilities (continued)

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

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

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

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

(c) Pro forma financial information

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

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

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

3. Business acquisitions and development projects (continued)

(d) Acquisition of U.S. wind farms

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

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

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

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

	Sandy Ridge	Senate	Minonk	Total
Cash	$ 1,365	$ 5,336	$ 16,528	$ 23,229
Property, plant and equipment	87,278	287,111	380,744	755,133
Derivative asset (liability)	1,655	(8,639)	3,736	(3,248)
Working capital	(1,365)	(5,336)	(16,528)	(23,229)
Asset retirement obligation	(1,662)	(1,697)	(2,262)	(5,621)
Total net assets acquired	$ 87,271	$276,775	$382,218	$746,264
Equity interests:				
APCo Class B membership interest	$ 35,169	$ 88,748	$145,151	$269,068
Additional paid in capital	192	919	1,250	2,361
Noncontrolling interests:				
Class A members	28,211	127,590	137,703	293,504
Class B members	23,699	59,518	98,114	181,331
	$ 87,271	$276,775	$382,218	$746,264

3. Business acquisitions and development projects (continued)

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

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

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

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

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

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

(e) Acquisition of noncontrolling interest in Calpeco

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

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

(f) Acquisition of solar energy project

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

(g) Acquisition of Shady Oaks wind power facility

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

3. Business acquisitions and development projects (continued)

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

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

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

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

(h) Agreement to acquire Regulated Gas Utility in Georgia

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

(i) Acquisition of Arkansas Regulated Water Utility

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

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

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

(j) Agreement to acquire New England Gas Company

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

4. Accounts receivable

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

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2012

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

2011

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

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

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

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

5. Property, plant and equipment (continued)

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

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

6. Intangible assets

Intangible assets consist of the following:

2012

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

2011

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

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

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

7. Regulatory matters

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

The utilities periodically file rate cases with their regulators. Rate cases seek to ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Regulated utilities use a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined.

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

7. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

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

7. Regulatory matters (continued)

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

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

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

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

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

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

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

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

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

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

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

8. Long-term investments and notes receivable

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

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

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

(a) Red Lily I

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

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

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

A second tranche of subordinated loan for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced in 2016 by the Company. The proceeds from this additional subordinated debt are required to be used to repay Tranche 2 of the Partnership’s senior debt, including APUC’s portion.

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated loan of up to $19,500, exercisable for a period of 90 days commencing in 2016. The fair value of the conversion option as at December 31, 2012 and 2011 was determined to be negligible.

9. Long-term liabilities

Long term liabilities consist of the following:

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

9. Long-term liabilities (continued)

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

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

APCo

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

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

9. Long-term liabilities (continued)

APCo (continued)

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

Liberty Utilities

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

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

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

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

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

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

APUC

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

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

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

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

10. Convertible debentures

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

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

11. Pension and other post-retirement benefits

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

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

(a) Net pension and OPEB obligation

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

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

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

(b) Net pension and OPEB obligation (continued)

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

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

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

(c) Assumptions

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

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

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

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

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

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

(c) Assumptions (continued)

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

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

(d) Benefit costs

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

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

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

(e) Plan assets

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

(f) Cash flows

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

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

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

12. Other assets

Other assets consist of the following:

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

13. Other long-term liabilities

Other long-term liabilities consist of the following:

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

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

14. Shareholders' capital

(a) Common shares

Number of common shares:

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

Authorized

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

On June 23, 2010, the Company's shareholders adopted a shareholders' rights plan (the "Rights Plan"). The Rights Plan has an initial term of three years. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

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

(i) Public offering

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

(ii) Conversion and redemption of convertible debentures

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

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

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

14. Shareholders' capital (continued)

(a) Common shares (continued)

(iii) Subscription receipts

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

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

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

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

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

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

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

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

(iv) Dividend reinvestment plan

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

14. Shareholders' capital (continued)

(b) Preferred shares

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

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

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

(c) Share-based compensation

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

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

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

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

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

i) Stock option plan

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

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

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

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

i) Stock option plan (continued)

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

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

Stock option activity during the period is as follows:

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

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

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

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

ii) Employee share purchase plan

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

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

iii) Directors deferred share units

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

iv) Performance share units

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

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

iv) Performance share units (continued)

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

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

15. Accumulated other comprehensive loss

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

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

16. Cash dividends

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

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

17. Income taxes

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

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

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

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

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

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

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

17. Income taxes (continued)

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

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

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

Deferred income taxes are classified in the financial statements as:

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

17. Income taxes (continued)

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

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

18. Sale of Small U.S. Hydro Facilities

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

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

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

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

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

19. Related party transactions

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

Transactions with APMI and Senior Executives

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

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

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

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

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

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

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

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

19. Related party transactions (continued)

Transactions with APMI and Senior Executives (continued)

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

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

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

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

Transactions with Emera

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

For the year ended December 31, 2012, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $6,096 (2011 – U.S. $6,564). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.

As of December 31, 2012, included in amounts due from related parties is $nil (2011 - $1,612) owed from Emera related to the unpaid contribution of their share of Liberty Energy (California) costs.

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

20. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares outstanding during the year. Diluted net income per share is computed using the weighted-average number of common shares and, if dilutive, potential common shares outstanding during the period. Potential common shares consist of the incremental common shares issuable upon the exercise of stock options, PSUs, DSUs, shareholders' rights and convertible debentures. The dilutive effect of outstanding stock options, PSUs, DSUs and shareholders' rights is reflected in diluted earnings per share by application of the treasury stock method while the dilutive effect of convertible debentures is reflected in diluted earnings per share by application of the as if converted method.

20. Basic and diluted net earnings per share (continued)

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

	2012	2011
Net earnings attributable to shareholders of APUC	$ 14,532	$ 23,381
Preferred shares dividend	769	—
Net earnings attributable to common shareholders of APUC – Basic and Diluted	$ 13,763	$ 23,381
Weighted average number of shares		
Basic	158,304,340	116,712,934
Dilutive effect of share-based awards	605,281	249,854
Diluted	158,909,621	116,962,788

The shares potentially issuable as a result of the convertible debentures as well as stock options of 1,354,531 respectively (2011 – 1,326,900) are excluded from this calculation as they are anti-dilutive.

21. Commitments and contingencies

a) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements, with the exception of those matters described below. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

i) On October 21, 2011 the Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5,400 (including interest) to the government of Québec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $5,800. In 2012, the Company paid an amount of $1,884 (2011 - $ nil) to the government of Québec in relation to the early years covered by the claim in order to mitigate the impact of accruing interests on any amount ultimately determined to be payable or recoverable.

21. Commitments and contingencies

(a) Contingencies

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

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

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $59,862 (U.S. $60,168) which at a discount rate of 3.5% represents the recorded accrual of $56,587 at December 31, 2012. This amount reflects the approval from the NHDES on December 10, 2012 of a Conceptual Remedial Design Report submitted to NHDES for removal of tar-impacted media at the Liberty Hill Road Site in New Hampshire. The NHDES approval at Liberty Hill Road Site reduced the overall cost estimate and consequently the Company withdrew its pending appeal. Remediation costs estimates for each site may vary, depending upon changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered.

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, at December 31, 2012 the Company has reflected a regulatory asset of $59,789 for the MGP and related sites.

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

2013	$ 2,433
2014	13,316
2015	18,836
2016	14,236
2017	996
Thereafter to 2046	10,045
	$59,862

21. Commitments and contingencies

b) Commitments (continued)

In addition to the commitments related to the proposed acquisitions disclosed in note 3 the following significant commitments exist at December 31, 2012.

As a result of the dam safety legislation passed in Quebec (Bill C93), APUC has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. The assessments have identified a number of remedial measures required to meet the new safety standards. APUC currently estimates further capital expenditures of approximately $16,900 over a period of five years related to compliance with the legislation.

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

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Purchased power	$ 56,276	$42,999	$41,316	$ —	$ —	$ —	$ 140,591
Gas delivery, service and supply agreements	25,165	16,792	14,977	5,777	5,207	52,461	120,379
Service agreements	27,147	18,610	17,827	22,253	23,023	566,903	675,763
Capital projects	3,110	500	—	—	—	—	3,610
Operating leases	4,405	4,099	3,792	3,284	3,202	69,562	88,344
Total	**$116,103**	**$83,000**	**$77,912**	**$31,314**	**$31,432**	**$688,926**	**$1,028,687**

Calpeco has entered into a five year all-purpose power purchase agreement with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2011 with a five year renewal option. The commitment amounts included in the table above are based on market prices as of December 31, 2012. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism. Granite State has several types of contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment.

22. Non-cash operating items

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

	2012	2011
Accounts receivable	$(14,895)	$(11,674)
Related party balances	1,476	145
Supplies and consumable inventory	(3,621)	(1,087)
Income tax receivable	(423)	(133)
Prepaid expenses	(4,629)	(2,071)
Accounts payable	(7,553)	3,991
Accrued liabilities	31,105	9,010
Current income tax liability	131	207
Net regulatory assets and liabilities	(5,475)	70
	$ (3,884)	$ (1,542)

23. Segmented information

APUC has two operating segments: APCo which owns or has interests in renewable energy facilities and thermal energy facilities and Liberty Utilities which owns and operates utilities in the United States of America providing water, wastewater and local electric and natural gas distribution services.

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

Effective July 2012, the Company changed its operational segments within Liberty Utilities to be aggregated and reported by the following geographic territories: Liberty Utilities (West), Liberty Utilities (Central) and Liberty Utilities (East). Liberty Utilities (West) is comprised of Calpeco and the water distribution and wastewater utilities located in Arizona. Liberty Utilities (Central) is comprised of the Midwest Gas Utilities and the water distribution and wastewater utilities located in Texas, Missouri and Illinois. Liberty Utilities (East) is comprised of the New Hampshire electric and gas utilities. The Company has restated the comparative items of segmented financial information to reflect the aggregation of segmented financial information adopted in the current year.

Operational segments

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

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

23. Segmented information (continued)

Operational segments (continued)

	Year ended December 31, 2012								
	Algonquin Power				Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ —	$ —	$ —	$ —	$ 71,734	$ 36,723	$ 108,457	$ —	$ 108,457
Regulated gas sales and distribution	—	—	—	25,802	—	49,916	75,718		75,718
Regulated water reclamation and distribution	—	—	—	9,127	37,296	—	46,423	—	46,423
Non-regulated energy sales	84,236	36,914	121,150	—	—	—	—	—	121,150
Waste disposal fees	—	14,288	14,288	—	—	—	—	—	14,288
Other revenue	1,925	1,680	3,605	—	152	94	246	—	3,851
Total revenue	86,161	52,882	139,043	34,929	109,182	86,733	230,844	—	369,887
Operating expenses	30,308	21,075	51,383	13,096	35,645	30,209	78,950	—	130,333
Regulated electricity purchased	—	—	—	—	43,861	24,348	68,209	—	68,209
Regulated gas purchased	—	—	—	13,648	—	23,813	37,461	—	37,461
Non-regulated fuel for generation	—	14,589	14,589	—	—	—	—	—	14,589
	55,853	17,218	73,071	8,185	29,676	8,363	46,224	—	119,295
Depreciation of property, plant and equipment	(18,823)	(9,977)	(28,800)	(3,333)	(11,120)	(7,129)	(21,582)	—	(50,382)
Amortization of intangible assets	(2,653)	(831)	(3,484)	(81)	(586)	—	(667)	—	(4,151)
Administration expenses	(9,424)	(2,212)	(11,636)	294	(4,091)	(1,223)	(5,020)	(2,952)	(19,608)
Foreign exchange gain	—	—	—	—	—	—	—	561	561
Interest expense	(15,060)	(2,054)	(17,114)	(96)	(8,066)	(694)	(8,856)	(9,971)	(35,941)
Interest, dividend and other income	2,038	509	2,547	—	2,113	461	2,574	2,118	7,239
Acquisition related costs	(3,155)	—	(3,155)	(1,442)	—	(3,112)	(4,554)	—	(7,709)
Gain/(loss) on derivative financial instruments	(2,954)	—	(2,954)	—			—	3,187	233
Earnings from continuing operations before income taxes	5,822	2,653	8,475	3,527	7,926	(3,334)	8,119	(7,057)	9,537
Loss from discontinued operations before income taxes	(1,907)	—	(1,907)	—	—	—	—	—	(1,907)
Earnings/(loss) before income taxes	$ 3,915	$ 2,653	$ 6,568	$ 3,527	$ 7,926	$ (3,334)	$ 8,119	$ (7,057)	$ 7,630
Property, plant and equipment	$1,157,062	$153,875	$1,310,937	$151,637	$350,053	$350,088	$ 851,778	$ —	$2,162,715
Intangible assets	29,480	6,132	35,612	2,613	18,556	—	21,169	—	56,781
Assets held for sale	24,390	—	24,390	—	—	—	—	—	24,390
Total assets	1,272,037	175,173	1,447,210	212,495	464,201	500,374	1,177,070	153,957	2,778,237
Capital expenditures	21,068	10,348	31,416	10,777	23,181	12,488	46,446	67	77,929
Acquisition of operating entities	245,718	—	245,718	128,890	—	295,297	424,187	—	669,905

23. Segmented information (continued)

Operational segments (continued)

	Year ended December 31, 2011								
	Algonquin Power				Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ —	$ —	$ —	$ —	$ 77,368	$ —	$ 77,368	$ —	$ 77,368
Regulated water reclamation and distribution	—	—	—	8,850	36,139	—	44,989	—	44,989
Non-regulated energy sales	81,645	46,666	128,311	—	—	—	—	—	128,311
Waste disposal fees	—	16,406	16,406	—	—	—	—	—	16,406
Other revenue	2,291	1,352	3,643	—	—	—	—	—	3,643
Total revenue	83,936	64,424	148,360	8,850	113,507	—	122,357	—	270,717
Operating expenses	25,400	19,857	45,257	4,270	34,453	—	38,723	38	84,018
Regulated electricity purchased	—	—	—	—	46,508	—	46,508	—	46,508
Non-regulated fuel for generation	—	24,628	24,628	—	—	—	—	—	24,628
	58,536	19,939	78,475	4,580	32,546	—	37,126	(38)	115,563
Depreciation of property, plant and equipment	(15,498)	(10,684)	(26,182)	(956)	(10,850)	—	(11,806)	—	(37,988)
Amortization of intangible assets	(3,007)	(2,735)	(5,742)	(81)	(610)	—	(691)	—	(6,433)
Administration expenses	(8,915)	(2,504)	(11,419)	(53)	(1,087)	—	(1,140)	(4,975)	(17,534)
Write down of long-lived assets	(678)	(13,430)	(14,108)		(1,058)		(1,058)	—	(15,166)
Foreign exchange loss	—	—	—	—	—	—	—	652	652
Interest expense	(9,834)	(2,228)	(12,062)	(61)	(7,404)	—	(7,465)	(10,910)	(30,437)
Interest, dividend and other income	2,143	(6)	2,137	—	488	—	488	3,034	5,659
Acquisition related costs	—	—	—	—	(2,767)	—	(2,767)	(198)	(2,965)
Loss on derivative financial instruments	(1,068)	—	(1,068)	—	—	—	—	(4,776)	(5,844)
Earnings from continuing operations before income taxes	21,679	(11,648)	10,031	3,429	9,258	—	12,687	(17,211)	5,507
Loss from discontinued operations before income taxes	(1,244)	—	(1,244)	—	—	—	—	—	(1,244)
Earnings/(loss) before income taxes	$ 20,435	$ (11,648)	$ 8,786	$ 3,429	$ 9,258	$ —	$ 12,687	$ (17,211)	$ 4,263
Property, plant and equipment	$398,037	$155,507	$553,544	$188,562	$178,003	$ —	$366,565	$ —	$ 920,109
Intangible assets	25,863	7,088	32,951	19,565	2,753	—	22,318	—	55,269
Assets held for sale	25,847	—	25,847	—	—	—	—	—	25,847
Total assets	482,543	176,269	658,812	228,597	212,035	—	440,632	182,863	1,282,307
Capital expenditures	25,610	13,601	39,211	774	20,393	—	21,167	367	60,745
Acquisition of operating entities	—	—	—	—	100,058	—	100,058	—	100,058

23. Segmented information (continued)

Operational segments (continued)

The majority of non-regulated energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2012 or 2011: Hydro Québec 17% (2011 - 17%), Manitoba Hydro 20% (2011 – 16%), and California PG&E 10% (2011 - 11%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

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

	2012	2011
Revenue		
Canada	$ 83,117	$ 88,900
United States	286,770	181,817
	$ 369,887	$270,717
Property, plant and equipment		
Canada	$ 472,333	$474,094
United States	1,690,382	446,015
	$2,162,715	$920,109
Intangible assets		
Canada	$ 29,480	$ 25,863
United States	27,301	29,406
	$ 56,781	$ 55,269

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

24. Financial instruments

(a) Fair value of financial instruments

	Carrying amount	2012 Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 22,937	$ 25,476	$ —	$ —	$25,476
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	12,695	12,695	—	12,695	—
Cross-currency swap designated as a foreign exchange hedge	408	408	—	408	—
Commodity contracts for regulatory operations	147	147	—	147	—
Total derivative financial instruments	13,250	13,250		13,250	
Total financial assets	$ 36,187	$ 38,726	$ —	$ 13,250	$25,476
Long-term liabilities	$770,826	$785,473	$ —	$785,473	$ —
Convertible debentures	960	1,319	1,319	—	—
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	9,012	9,012	—	9,012	—
Cross-currency swap designated as a foreign exchange hedge	2,078	2,078	—	2,078	—
Interest rate swaps not designated as a hedge	4,778	4,778	—	4,778	—
Energy derivative contracts	287	287	—	287	—
Commodity contracts for regulated operations	1,661	1,661	—	1,661	—
Total derivative financial instruments	17,816	17,816	—	17,816	
Total financial liabilities	$789,602	$804,608	$1,319	$803,289	$ —

24. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

	Carrying amount	2011 Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 24,534	$ 24,534	$ —	$ —	$24,534
Total financial assets	$ 24,534	$ 24,534	$ —	$ —	$24,534
Long-term liabilities	$332,716	$338,264	$ —	$338,264	$ —
Convertible debentures	122,297	162,195	162,195	—	—
Derivative financial instruments:					
Interest rate swaps not designated as a hedge	6,975	6,975	—	6,975	—
Energy derivative contracts	1,169	1,169	—	1,169	—
Total derivative financial instruments	8,144	8,144	—	8,144	—
Total financial liabilities	$463,157	$508,603	$162,195	$346,408	$ —

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

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

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value (a level 2 measurement) at December 31, 2012 and 2011 due to the short-term maturity of these instruments.

Notes receivable fair values have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management. Such estimate is significantly influenced by unobservable data and therefore this fair value is subject to estimation risk.

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

24. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company's Level 2 fair value derivative instruments primarily consist of swaps, options, and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace.

The Red Lily conversion option is measured at fair value on a recurring basis using unobservable inputs (Level 3). The fair value is based on an income approach using an option pricing model that includes various inputs such as energy yield function from wind, estimated cash flows and a discount rate of 8.5%. The Company used a discount rate believed to be most relevant given the business strategy. There was no change in fair value of $nil during the years ended December 31, 2012 or 2011.

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

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2012 or 2011.

(b) Derivative instruments

Derivative instruments are recognized on the balance sheet as either assets or liabilities and measured at fair value each reporting period.

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas service territories. The Company's strategy is to minimize fluctuations in gas sales prices to regulated customers. The accounting for these derivative instruments is subject to current guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the accompanying balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 7 (v)).

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

	2012
Financial contracts: Gas swaps	3,353,420
Gas options	787,960
	4,141,380

24. Financial instruments (continued)

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

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

	2012	2011
Regulatory assets:		
Gas swap contracts	$1,555	$ —
Gas option contracts	$ 106	$ —
Regulatory liabilities:		
Gas swap contracts	$ 90	$ —
Gas option contracts	$ 57	$ —

(ii) Cash flow hedges

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

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Pay floating price (per MW-hr)
196,231	May 2012 – December 2016	U.S. $ 66.57	AESO
1,144,045	January 2013 – December 2022	U.S. $ 42.81	PJM Western HUB
4,885,898	January 2013 – December 2022	U.S. $ 30.25	NI HUB
4,995,968	January 2013 – December 2027	U.S. $ 36.46	ERCORT North HUB

The effects on the Consolidated Statement of Operations of derivative financial instruments designated as cash flow hedge consist of the following:

	2012	2011
Gain on derivative instruments (ineffective portion)	$105	$ —

The following table summarizes changes in other comprehensive income attributable to derivative financial instruments designated as a hedge:

	2012	2011
Effective portion of cash flow hedge, gain	$ 5,214	$ —
Gain (loss) realized on cash flow hedge	(49)	—
	$ 5,165	$ —
Less noncontrolling interest	(1,572)	$ —
Change in fair value of cash flow hedge in other comprehensive income	$ 3,593	$ —

24. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The Company expects $3,852 of unrealized gains currently in accumulated other comprehensive loss to be reclassified into net earnings within the next twelve months, as the underlying hedged transactions settle.

(iii) Foreign exchange hedge of net investment in foreign operation

The Company periodically uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

Concurrent with its $150,000 debentures offering in December 2012, APCo entered into a cross currency swap, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. APCo designated the entire notional amount of the cross currency fixed for fixed interest rate swap and related short-term USD payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the USD accruals that are designated as, and are effective as, an economic hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in other comprehensive income) related to the net investment. A foreign currency loss of $1,669 was recorded in other comprehensive income in 2012.

(iv) Other derivatives

APCo provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Assets are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short term financial forward energy purchase contracts which are derivative instruments. In January 2011, APUC entered into electricity derivative contracts for a term ending February 2014, which are net settled fixed-for-floating swaps whereby APUC will pay a fixed price and receive the floating or indexed price on a notional quantity of 91,216 MW-hrs of energy over the remainder of the contact term at an average rate of approximately U.S. $52.89 per MW-hr. The estimated fair value of these forward energy hedge contracts at December 31, 2012 was a net liability of $286 (2011 - $1,169). These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

24. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

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

	2012	2011
Change in unrealized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ —	$ (45)
Interest rate swaps	(2,197)	1,536
Energy derivative contracts	(825)	833
Total change in unrealized loss/(gain) on derivative financial instruments	$(3,022)	$2,324
Realized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ (187)	$ 691
Interest rate swaps	2,094	2,138
Energy derivative contracts	987	691
Total realized loss on derivative financial instruments	$ 2,894	$3,520
Loss/(gain) on derivative financial instruments accounted for as hedges	$ (128)	$5,844
Ineffective portion of derivatives financial instruments accounted for as hedges	$ (105)	—
Loss/(gain) on derivative financial instruments	$ (233)	$5,844

(c) Risk management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view to mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk, liquidity risk, foreign currency risk and interest rate risk, and how the Company manages those risks.

24. Financial instruments (continued)

(c) Risk management (continued)

Credit risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents accounts receivable and notes receivable. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders in Canada all of which have a credit rating of A or better. The Company does not consider the risk associated with accounts receivable to be significant as over 80% of revenue from power generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Utility Services business unit which consists of water and wastewater utilities, electric utilities and gas utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of U.S. $35,688 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition the state regulators of the Company's utilities allow for a reasonable bad debt expense to be incorporated in the rates and therefore ultimately recoverable from rate payers.

As at December 31, 2012 the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2012	
	Canadian $	US $
Cash and cash equivalents and restricted cash	$ 20,452	$ 39,936
Other current assets	833	—
Accounts receivable	14,904	79,680
Allowance for Doubtful Accounts	—	(4,382)
Notes Receivable	20,747	2,201
	$ 56,936	$117,435

24. Financial instruments (continued)

(c) Risk management (continued)

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As at December 31, 2012, in addition to cash on hand of $53,122 the Company had $224,310 available to be drawn on its senior debt facilities. The senior credit facilities contain covenants which may limit amounts available to be drawn.

The Company's liabilities mature as follows:

	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years	Total
Long term debt obligations	$ 1,768	$ 58,490	$ 14,853	$695,715	$ 770,826
Advances in aid of construction	591	—	—	71,626	72,217
Interest on long term debt	41,090	80,415	71,576	136,671	329,752
Accounts payable and due to related parties	36,094	—	—	—	36,094
Environmental obligation	2,433	32,152	15,232	10,045	59,862
Accrued liabilities	99,468	—	—	—	99,468
Derivative financial instruments:					
Cross- currency swap	—	—	—	2,077	2,077
Interest rate swaps	1,968	2,810	—	—	4,778
Energy derivative and commodity contracts	245	1,703	384	8,629	10,961
Capital lease payments	134	136	—	—	270
Other obligations	4,217	3,100	380	15,972	23,669
Total obligations	$188,008	$178,806	$102,425	$940,735	$1,409,974

Foreign currency risk

The Company is exposed to currency fluctuations from its U.S. based operations. APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations.

In August 2012, APCo designated the amounts drawn on its bank credit facility denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The foreign currency transaction gain or loss on the outstanding U.S. dollar denominated balance of APCo's facility that is designated a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in other comprehensive income) related to the net investment, to the extent it is effective as a hedge. A foreign currency loss of $452 was recorded in other comprehensive income.

Interest rate risk

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project specific debt and its revolving credit facility, its interest rate swaps as well as interest earned on its cash on hand. The Company does not currently hedge that risk.

24. Financial Instruments (continued)

(c) Risk management (continued)

Interest rate risk (continued)

APCo is party to an interest rate swap whereby, the Company pays a fixed interest rate of 4.47% on a notional amount of $64,276 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. At December 31, 2012, the estimated fair value of the interest rate swap was a liability of $4,778 (2011 – liability of $6,975). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

25. Subsequent event

Subsequent to year-end, effective January 1, 2013, the Company issued 100 redeemable Series C preferred shares in exchange for Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APCo and the legal owner of the St. Leon facility (note 19). Thirty six of the Class C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 have a contractual cumulative cash dividend paid quarterly based on a prescribed payment schedule out to the redemption date in 2031. Consequently, these shares will be accounted for as liabilities in the financial statements. The cumulative dividends are indexed in proportion to the increase in CPI over the term of the shares. The dividend is intended to approximate the distributions that otherwise would have accrued to holders of Class B limited partnership units.

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

The Class C preferred shares will initially be measured at its estimated fair value of $18,205 based on the present value of the expected contractual cash flows including dividends and redemption amount, discounted at a rate of 5.0%. The recognition of the initial fair value of $18,205 will result in an adjustment to equity of the shareholders of the Company as the Class B shares had a nominal carrying amount prior to the exchange. The preferred shares will be accounted for under the effective interest method, resulting in accretion of interest expense over the term of the shares. Dividend payments are recorded as a reduction of the Class C Preferred Share carrying value.

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

2013	$ 802
2014	1,078
2015	1,046
2016	919
2017	870
Thereafter to 2031, including redemption amount	26,706
Less amounts representing interest	(13,216)
Final redemption of Class C Preferred Shares	$ 18,205

26. Comparative figures

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

Management's Discussion and Analysis

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

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2012. The Management's Discussion and Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2012 and 2011. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of March 14, 2013.

Caution concerning forward-looking statements and non-GAAP Measures

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

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

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

Overview and Business Strategy

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

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

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

Algonquin Power Co.

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

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

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

Liberty Utilities Co.

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

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

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

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

wastewater collection utilities serve approximately 11,500 water and wastewater customers located in the States of Arkansas, Illinois, Missouri, and Texas.

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

Major Highlights

Corporate Highlights

Dividend Increased to $0.31 per Common Share Annually

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

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

Strengthened Balance Sheet

Issuance of $120M Preferred Shares

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

Emera Subscription Receipts

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

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

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

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

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

Conversion of Series 2A Convertible Debentures to Equity

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

Conversion and Redemption of Series 3 Convertible Debentures to Equity

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

APUC Credit Facility

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

Liberty Utilities Highlights

Agreement to Acquire New England Utility

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

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

Agreement to Acquire Georgia Utility

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

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

Acquisition of Remaining Interest in the California Utility

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

Acquisition of New Hampshire Utility

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

utility provides natural gas service to over 87,000 connections in five counties and 30 communities in New Hampshire.

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

Acquisition of Missouri Utility

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

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

Acquisition of Arkansas Utility

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

U.S. Debt Private Placements

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

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

U.S. $100 million Acquisition Term Facility

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

Expansion of Liberty Utilities Credit Facility

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

Algonquin Power Co. Highlights

Acquisition of U.S. Wind Facilities

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

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

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

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

Acquisition of Shady Oaks Wind Facility

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

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

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

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

APCo $150 million Senior Unsecured Debentures

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

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

APCo Credit Facility

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

Completion of Windsor Locks Repowering

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

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

Sale of Small U.S. Hydro Facilities

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

2012 Annual Results from Operations

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

Key Selected Annual Financial Information

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

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

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

[3] Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.
[4] Long term debt includes current and long term portion of debt and convertible debentures.

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

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

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

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

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

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

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

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

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided

by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

2012 Three month results from operations

Key Selected Fourth Quarter Financial Information

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

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

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

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

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

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

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

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

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

The increase in Adjusted EBITDA was primarily due to increased revenues from EnergyNorth Gas Utility, Granite State Electric Utility, Midwest Gas Utilities, and the U.S. Wind Project acquisitions, and increased demand at the Liberty Utilities (West)'s electric distribution utility. These items were partially offset by lower results from operations primarily from increased energy costs for APCO's energy sales group, lower revenues from APCo's EFW facility due to the expiry of the Region of Peel contract, and reduced wind resources at APCo's St Leon facility. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended December 31, 2012, net income attributable to Shareholders totalled $6.4 million as compared to net loss attributable to Shareholders of $8.5 million during the same period in 2011, an increase of $14.9 million. Net income per share totalled $0.04 for the three months ended December 31, 2012, as compared to net loss per share of $0.07 during the same period in 2011.

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

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

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

Outlook

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

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

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



APCo: Renewable Energy Division

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

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

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

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

4 While most of APCo's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division, as compared to the same period in the prior year.

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

2012 Annual Operating Results

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

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

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

For the year ended December 31, 2012, revenue from energy sales in the Renewable Energy Division totalled $84.2 million, as compared to $81.6 million during the same period in 2011. As the purchase of energy by the Energy Services Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the year ended December 31, 2012, net revenue from energy sales in the Renewable Energy Division totalled $75.3 million, as compared $77.8 million during the same period in 2011.

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

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

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

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

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

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

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

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

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

2012 Fourth Quarter Operating Results

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

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

For the quarter ended December 31, 2012, revenue from energy sales in the Renewable Energy Division totalled $21.5 million, as compared to $22.3 million during the same period in 2011. As the purchase of energy by the Energy Services Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the quarter ended December 31, 2012, net revenue from energy sales in the Renewable Energy Division totalled $19.8 million, as compared $21.6 million during the same period in 2011.

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

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

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

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

ended December 31, 2012. The division reported decreased energy purchase costs of $0.1 million as a result of the weaker U.S. dollar as compared to the same period in 2011.

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

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

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

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

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

APCo: Thermal Energy Division

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

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

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

2012 Annual Operating Results

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

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

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

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

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

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

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

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

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

2012 Fourth Quarter Operating Results

For the quarter ended December 31, 2012, the Thermal Energy Division produced 80.5 GW-hrs of energy as compared to 126.5 GW-hrs of energy in the comparable period of 2011. The decrease in energy production

was due primarily to the installation of the new Titan turbine which is a smaller, more efficient turbine, sized to optimize the energy and steam requirements of the steam host compared to the larger, less efficient Frame 6 turbine that was operating the previous year.

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

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

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

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

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

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

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

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

APCo: Development Division

The Development Division works to identify, develop and construct new power generating facilities, as well as to identify, and acquire, operating projects that would be complementary and accretive to APCo's existing portfolio. The Development Division is focused on projects within North America and is committed to working proactively with all stakeholders including local communities. APCo's approach to project development and acquisition is to maximize the utilization of internal resources while minimizing external costs. This allows projects to mature to the point where most major elements and uncertainties are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a power purchase agreement, obtaining the required financing commitments to develop the project, completion

of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that APCo will begin construction or execute an acquisition agreement.

Projects Currently in Development

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

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

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

Chaplin Wind

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

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

Amherst Island Wind

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

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

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

Morse Wind Project

The Morse wind project is comprised of three contiguous projects with 25 MW of aggregate installed generating capacity. The project is to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina. It

is contemplated that the project will have additional land under lease or option in order to facilitate future expansion.

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

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

Quebec Community Wind Projects

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

1. Saint-Damase

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

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

2. Val-Éo

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

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

Cornwall Solar

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

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

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

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

APCo Outlook

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

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

Liberty Utilities

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

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

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

The Liberty Utilities (West) region is currently comprised of regulated electrical and water distribution and wastewater collection utility systems. The regulated electrical distribution utility serves approximately 46,955 active electric connections in the State of California. The Liberty Utilities (West) region's regulated water and

wastewater utility systems serve approximately 66,550 water and wastewater connections located in the State of Arizona. These utilities systems, previously reported in the Liberty Utilities (South) region, have now been combined with Liberty Utilities (West) for reporting purposes, effective July 1, 2012.

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

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

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

Liberty Utilities: West Region

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

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

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

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

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

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

[1] Represents 100% of investment in the Calpeco Electric Utility

2012 Annual Operating Results

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2012 Fourth Quarter Operating Results

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

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

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

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

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

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

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

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

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

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

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

Liberty Utilities: Central Region

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

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

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

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

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

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

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

2012 Annual Operating Results

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2012 Fourth Quarter Operating Results

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

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

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

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

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

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

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

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

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

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

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

In the June 30, 2012 Interim MD&A, guidance was provided on the Liberty Utilities (Central)'s expected operating results over the 12 month period ending June 30, 2013. For the three months ended December 31,

2012, Midwest Gas Utilities' EBITDA of U.S. $3.9 million did not meet the guidance EBITDA of U.S. $4.6 million. The decreased EBITDA was due primarily to lower than expected natural gas usage in the states of Missouri, Illinois, and Iowa with Central recording actual usage of 2,001,050 MMBTU compared to the guidance of 2,006,230 MMBTU. A portion of the decreased usage results from actual active natural gas connections being 82,050 compared to the guidance of 83,223 active natural gas connections a difference of 928 active connections.

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

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

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

Liberty Utilities: East Region

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

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

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

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

connections. Liberty Utilities (East) reports active connections, exclusive of vacant connections rather than total connections.

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

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

1 Granite State Electric Utility and EnergyNorth Gas Utility were acquired on July 3, 2012.

2 Natural Gas costs are shown net of U.S. $4.5 million regulatory authorized deferral related to an under recovery of actual gas costs.

2012 Annual Operating Results

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2012 Fourth Quarter Operating Results

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Outlook – Liberty Utilities

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

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

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

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

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

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

APUC: Corporate and Other Expenses

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

2012 Annual Corporate and Other Expenses

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

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

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

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

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

2012 Fourth Quarter Corporate and Other Expenses

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

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

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

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

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

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

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

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

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

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

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

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

Reconciliation of adjusted net earnings to net earnings

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

earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP.

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

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

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

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

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

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

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

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

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

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

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

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

Summary of Property, Plant and Equipment Expenditures

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

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

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

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

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, working capital and bank credit facilities to finance its property, plant and equipment expenditures and other commitments.

2012 Annual Property Plant and Equipment Expenditures

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

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

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

2012 Fourth Quarter Property Plant and Equipment Expenditures

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

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

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

Quebec Dam Safety Act

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

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

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

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

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

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

Liquidity and Capital Reserves

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

Bank Credit Facilities

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

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

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

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

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

Long Term Debt

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

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

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

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

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

Contractual Obligations

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

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

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

Equity

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

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

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

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

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

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

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

Emera subscription receipts

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

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

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

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

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

SHARE BASED COMPENSATION PLANS

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

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

STOCK OPTION PLAN

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

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

As at December 31, 2012, APUC had 3,750,727 options issued and outstanding. APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options'

vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date.

PERFORMANCE SHARE UNITS

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

DIRECTORS DEFERRED SHARE UNITS

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

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

EMPLOYEE SHARE PURCHASE PLAN

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

MANAGEMENT OF CAPITAL STRUCTURE

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

APUC's objectives when managing capital are:

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

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

RELATED PARTY TRANSACTIONS

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

Transactions with APMI and Senior Executives

- APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the year ended December 31, 2012 were $333 (2011 - $327).
- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. During the year ended December 31, 2012, APUC incurred costs in connection with the use of the aircraft of $598 (2011 - $453)

and amortization expense related to the advance against expense reimbursements of $279 (2011 - $274). At December 31, 2012, the remaining amount of the advance was $nil (December 31, 2011 - $279).

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

Transactions with Emera

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

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

Business Associations with APMI and Senior Executives

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

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

i) Rattlebrook hydroelectric generating facility

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

ii) St. Leon wind power generating facility

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

iii) Brampton Cogeneration Inc.

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

iv) Long Sault Rapids hydroelectric generating facility

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

v) Chartered aircraft

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

vi) Office lease

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

vii) Operations services

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

viii) Sanger construction management

As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee. An amount of U.S. $0.6 million has been accrued as an estimate of the final fee owed to APMI. This was settled pursuant to the Agreement.

ix) Clean Power Income Fund

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

x) Red Lily I

APMI was an early developer of the 26 MW Red Lily I wind power generation facility. As such it is entitled to a royalty fee based on a percentage of operating revenue and a development fee from Red Lily I. This relationship was settled pursuant to the Agreement.

xi) Trafalgar

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

Settlement of Other Business Associations

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

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

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

TREASURY RISK MANAGEMENT

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

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

Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 59% of EBITDA in 2012 and 75% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $6.3 million ($0.04 per share) on an annual basis.

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

Market price risk

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

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

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

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

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

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

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

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

Credit/Counterparty risk

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

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

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

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

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

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

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

Interest rate risk

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

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

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

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

Liquidity risk

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

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

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

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

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

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

Commodity price risk

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Water is not subject to any material commodity price risk. In this regard, a discussion of this risk is set out as follows:

- APCo's Sanger facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in an increase in net revenue by approximately $0.2 million on an annual basis.
- APCo's Windsor Locks facility's ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to Ahlstrom. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.
- APCo's BCI facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in an increase in net revenue by approximately $0.1 million.
- AES provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 250,000 MW-hrs in fiscal 2013. While the Tinker facility is expected to provide a significant portion of the energy required to service these customers, AES anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. In the event that AES was required to purchase all of its energy requirements at ISO-NE spot rates, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $2.5 million on an annualized basis. This risk is mitigated through the use of short-term financial energy hedge contracts. AES has committed to acquire approximately 72,000 MW-hrs of net energy over the next 12 months at an average rate of

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

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

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

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

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

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

OPERATIONAL RISK MANAGEMENT

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

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

Mechanical and Operational Risks

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

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

The electricity distribution systems owned by Liberty Utilities are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

The gas distribution systems owned by Liberty Utilities are subject to significant risks which may lead to fire and/or explosion which may have serious impact on life and property. Risks include third party damage, significant leaks, type/age of pipelines and severe weather events.

These risks are mitigated through the diversification of APUC's operations, both operationally (APCo and Liberty Utilities) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses.

Regulatory Risk

Profitability of APUC businesses is in part dependant on regulatory climates in the jurisdictions in which it operates. In the case of some APCo hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue.

Liberty Utilities' facilities are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on electricity and natural gas distribution utilities. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Electricity and natural gas distribution utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities, and while Liberty Utilities believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Liberty Utilities regularly works with its governing authorities to manage the affairs of the business.

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

Liberty Utilities' facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Utilities has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging distribution facilities and expenses associated with providing new sources of commodity supply can generally be included in the facility's rate base and thus Liberty Utilities expects to be allowed to earn a return on such investment.

In conjunction with the recent acquisitions the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements to: (i) remove of wind farm facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants) and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas main when removed from the pipeline system, (iii) clean and remove storage tanks containing waste oil and other waste contaminants, and (iv) remove asbestos upon major renovation or demolition of structures and facilities.

Environmental Risks

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

Liberty Utilities faces environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of an electrical distribution system are related to potential accidental release of mineral oil to the environment from non-operational events and the management of hazardous and universal waste in accordance with the various Federal, State and local environmental laws. Like most other industrial companies, Liberty Utilities generates some hazardous wastes as a result of its operations. Under Federal and State Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, Liberty Utilities investigates promptly all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation.

The primary risks associated with the operation of gas distribution systems are related to uncontrolled natural gas releases, equipment damage by construction equipment/third parties or severe weather events. The gas distribution assets are heavily regulated by the Pipeline Hazardous Material Safety Administration (PHMSA) under the United States Department of Transportation and their respective State regulations in which the assets are located. Gas Distribution systems are subject to detailed annual inspections by State Regulatory Agency to ensure strict adherence to applicable regulations. PHMSA reviews the Company's policies in reference to operation and maintenance, construction, training, emergency response, reporting, contractor management and measurements. Liberty monitors all aspects of pipeline safety and quickly mitigates any identified concerns.

Liberty Utilities (East)'s ongoing operations and historic activities are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the United States Environmental Protection Agency and the New Hampshire Department of Environmental Services ("NHDES"). Similar to other industrial companies, the gas and electric distribution utilities generate certain hazardous wastes. Under federal and state Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of regulated utilities these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

Prior to their acquisition by Liberty Utilities, EnergyNorth Gas Utility and Granite State Electric Utility were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Liberty Utilities is currently investigating and remediating, as necessary, those MGP and related sites where it is the lead project manager in accordance with plans submitted to the NHDES. The Liberty Utilities believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position.

Liberty Utilities estimates the remaining cost of these MGP-related environmental cleanup activities will be $68,180 which at a discount rate of 3.5% represents $56,587 at December 31, 2012, which has been accrued as Liberty Utilities' estimate of costs for known issues. By rate orders, the Regulator provided for the recovery of site investigation and remediation costs and accordingly, at December 31, 2012 the Company has reflected a regulatory asset of $55,721 for the remediation of the MGP and related sites.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2012.

Cycles and Seasonality

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized.

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

Liberty Utilities (West) and Liberty Utilities (Central)'s demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

Liberty Utilities (West) region's demand for energy is primarily affected by weather conditions and conservation initiatives. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. Liberty Utilities (West) provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts to revenues.

Prior to January 1, 2013, Liberty Utilities (West) was exposed to volume sales risk related to seasonal weather variations. Effective on January 1, 2013, pursuant to a CPUC approved Rate Case decision, a Base Revenue Requirement Balancing Account (BRAAM) rate mechanism has been implemented. The BRAAM removes the seasonal variations of the revenues and flattens the net revenue (minus Fuel, Purchased Power, ECAC) to a monthly rate of $3.0 million or $35.5 million annually. This substantially eliminates the risk of revenue variations associated with seasonal weather changes.

Liberty Utilities (East) and Liberty Utilities (Central) natural gas demand is driven by the seasonal heating requirements of its residential, commercial, and industrial customer. That is, the colder the weather the greater the demand for natural gas to heat homes and businesses. As such, Liberty Utilities (East) and Liberty Utilities (Central)'s natural gas demand profiles typically crests in the winter months of January and February and declines in the summer months of July and August.

Litigation risks and other contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

APCo owns debt on seven hydroelectric facilities owned by Trafalgar. In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings.

With respect to the civil proceedings, the Second Circuit Court of Appeal dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. On April 3, 2012, the District Court

granted APUC summary judgment on its counter-claims against Trafalgar. The District Court found that Trafalgar was in default of the indenture and the loan agreements and that APUC was entitled to proceed to enforce its rights against its collateral. Trafalgar has filed a notice of appeal of the Memorandum-Decision and Order. Algonquin filed its brief on October 19, 2012 with a hearing dated anticipated in the first quarter of 2013. The bankruptcy proceedings are continuing with a Second Circuit Court of Appeal hearing scheduled for December 12, 2012 to hear the appeal of the District Court's October 25, 2011 decision holding that Algonquin does not have a security interest in the monies transferred by Trafalgar before it filed for bankruptcy protection.

With respect to the bankruptcy proceedings, on January 30, 2013, the U.S Second Circuit Court of Appeals held that APCo did have a security interest in Trafalgar's engineering malpractice claim and its proceeds. On February 20, 2013, Trafalgar filed a petition for a rehearing with the U.S, Second Circuit Court of Appeals.

On October 21, 2011 the Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5.4 million (including interest) to the government of Québec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years. The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. The potential unrecoverable loss, if any, for the related prior periods could be up to $5.8 million. The parties are attempting to resolve this matter through good faith negotiations.

Obligations to serve

Liberty Utilities may have facilities located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, Liberty Utilities may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the eight quarter ended December 31, 2012:

Millions of dollars (except per share amounts)	1st Quarter 2012	2nd Quarter 2012	3rd Quarter 2012	4th Quarter 2012
Revenue	$ 63.3	$ 64.6	$ 98.7	$ 143.1
Adjusted EBITDA	23.0	25.1	24.8	33.4
Net earnings / (loss) attributable to shareholders from continuing operations	2.5	6.3	0.04	6.6
Net earnings / (loss) attributable to shareholders	2.3	6.1	(0.2)	6.4
Net earnings / (loss) per share from continuing operations	0.02	0.04	0.00	0.04
Net earnings / (loss) per share	0.02	0.04	0.00	0.04
Adjusted net earnings	4.3	7.1	3.9	5.4
Adjust net earnings per share	0.03	0.05	0.02	0.03
Total Assets	1,265.6	1,416.0	1,967.1	2,778.2
Long term debt*	403.7	473.8	705.1	771.8
Dividend declared per common share	0.07	0.07	0.08	0.08

	1st Quarter 2011	2nd Quarter 2011	3rd Quarter 2011	4th Quarter 2011
Revenue	$ 70.1	$ 64.9	$ 65.1	$ 70.5
Adjusted EBITDA	26.7	27.9	25.8	24.3
Net earnings / (loss) attributable to shareholders from continuing operations	4.8	7.0	19.6	(7.7)
Net earnings/(loss) attributable to shareholders	5.0	7.3	19.6	(8.5)
Net earnings / (loss) per share from continuing operations	0.05	0.06	0.16	(0.6)
Net earnings/(loss) per share	0.05	0.06	0.16	(0.07)
Adjusted net earnings	5.1	7.9	22.4	3.6
Adjust net earnings per share	0.05	0.07	0.19	0.03
Total Assets	1,175.8	1,177.7	1,263.1	1,282.6
Long term debt*	507.0	451.1	472.2	455.0
Dividend declared per common share	0.07	0.07	0.07	0.07

* Long term debt includes current and long term portion of debt and convertible debentures

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $63.3 million and $143.1 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between net earnings attributable to shareholders of $19.6 million and a net loss of $8.5 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

Disclosure Controls

At the end of the fiscal year ended December 31, 2012, APUC carried out an evaluation, under the supervision of and with the participation of APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2012, APUC's disclosure controls and procedures are effective.

Internal controls over financial reporting

APUC's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of APUC; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of APUC are being made only in accordance with authorizations of management and directors of APUC; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of APUC's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

During the year ended December 31, 2012, APUC acquired EnergyNorth Gas Utility, Granite State Electric Utility, the Midwest Gas Utilities, and the Sandy Ridge, Minonk and Senate Wind Facilities. The financial information for these business acquisitions is included in this MD&A and in Note 3 to the consolidated financial statements. As permitted by National Instrument 52-109 and the U.S. Securities and Exchange Commission, the Company excluded these acquisitions from its evaluation of the effectiveness of APUC's internal controls over financial reporting as of December 31, 2012 due to the complexity associated with assessing internal controls during integration efforts and the proximity of some of the acquisitions to year-end.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2012 based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2012.

During the year ended December 31, 2012, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. APUC continues to implement its internal control structure over the operations of the acquired businesses discussed above.

Critical Accounting Estimates and Polices

The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, recoverability of deferred tax assets, rate-regulation, unbilled revenue, pension and postretirement benefits, and fair value of derivatives. Actual results may differ from these estimates.

APUC's significant accounting policies are discussed in Note 1 to the consolidated financial statements. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

Estimated useful lives and recoverability of Long-Lived Assets and Intangibles

The provisions for depreciation of utility property and equipment for financial reporting purposes are made on the straight-line method based on the estimated service lives of the assets. Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process. Non-regulated property and equipment are depreciated on a straight-line basis over useful lives of the related assets. Management believes the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries could result in a reduction of the estimated useful lives of those non-regulated assets or in an impairment write-down of the carrying value of these properties.

The carrying value of long-lived assets, including identifiable intangibles, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable. Some of the factors APUC considers as indicators of impairment include whether a facility is operating, its plan for return to service, external influences such as natural disasters, energy pricing and profitability and changes in regulation. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, interest rates, regulatory matters and operating costs could negatively affect the fair value of APUC's assets and result in an impairment charge.

Valuation of Deferred Tax Assets

Income taxes are accounted for using the asset and liability method. Under this method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Although management believes the assumptions, judgments and estimates are reasonable, changes in tax laws and changes in operations could significantly impact the amounts provided for income taxes in our financial statements.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to Liberty Utilities' operations. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or write down.

Unbilled Energy Revenues

Revenues related to natural gas, electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of natural gas, energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Derivatives

APUC uses derivative instruments to manage exposure to changes in commodity prices, foreign exchange rates and interest rates. Derivative instruments that do not meet the normal purchases and sales exception are recorded at fair value. Changes in the derivative's fair value are recognized as regulatory assets or liabilities when the regulator permits recovery of the hedging strategy. For derivative designated in a cash flow hedge relationship, the effective portion of the change in fair value is deferred to accumulated other comprehensive income, until the hedged transaction occurs and is recognized in earnings. The ineffective portion is immediately recognized in earnings. For derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations, foreign currency transaction gain or loss that are effective as an economic hedge of the net investment in a foreign operation are reported in other comprehensive income.

Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets adjusted for nonperformance risk. A significant change in estimate could affect APUC's results of operations.

Pension and Postretirement Benefits

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and post-retirement benefit plans for qualifying employees in the related acquired businesses. The obligations and related costs are calculated using actuarial concepts, which include critical assumptions related to the discount rate, expected rate of return on plan assets and medical cost trend rates. These assumptions are important elements of expense and/or liability measurement and are updated on an annual basis, or upon the occurrence of significant events. A significant change in estimate could affect APUC's results of operations. In addition, the determination of the fair value of pension and postretirement benefits assets and liabilities acquired in the business acquisitions has been based upon management's preliminary estimates and assumptions. The Company will continue to review information and perform further analysis. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts noted.

Additional disclosure of APUC's critical accounting estimates is also available SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Exhibit 99.4



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Consent of Independent Registered Public Accounting Firm

We consent to the inclusion in this annual report on Form 40-F of:

- our Report of Independent Registered Public Accounting Firm dated March 14, 2013 on the consolidated balance sheets of Algonquin Power & Utilities Corp. (the "Company") as of December 31, 2012 and December 31, 2011, and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows for the years then ended; and,
- our Report of Independent Registered Public Accounting Firm dated March 14, 2013 on the Company's internal control over financial reporting as of December 31, 2012;

each of which is contained in this annual report on Form 40-F of the Company for the fiscal year ended December 31, 2012. We also hereby consent to the incorporation by reference of the above mentioned reports into the Registration Statement on Form S-8 (Registration No. 333-177418) of the Company.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
March 28, 2013

Exhibit 99.5

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, Ian E. Robertson, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 28, 2013

By: /s/ Ian E. Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

Exhibit 99.6

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, David Bronicheski, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 28, 2013

By: /s/ David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer

Exhibit 99.7

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the "Corporation") on Form 40-F for the year ended December 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ian E. Robertson, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: March 28, 2013

By: /s/ Ian Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

Exhibit 99.8

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the "Corporation") on Form 40-F for the year ended December 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David Bronicheski, Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: March 28, 2013

By: /s/ David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer