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, 2009

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)

1600
(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

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:

þ Annual Information Form þ 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, 2009, there were 93,064,120 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 þ 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 ¨ No ¨

DISCLOSURE CONTROLS AND PROCEDURES

The information provided under the heading “Disclosure Control and Procedures” (page 49) contained in Management’s Discussion and Analysis for the fiscal year ended December 31, 2009, 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

The information provided under the heading “Internal Control over Financial Reporting” (page 49) contained in Management’s Discussion and Analysis for the fiscal year ended December 31, 2009, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

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

This annual report on Form 40-F does not include an attestation report of Algonquin Power & Utilities Corp.’s registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

c. Changes in internal control over financial reporting

The information provided under the heading “Changes in Internal Control over Financial Reporting” (page 49) contained in Management’s Discussion and Analysis for the fiscal year ended December 31, 2009, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

AUDIT COMMITTEE FINANCIAL EXPERTS

Algonquin Power & Utilities Corp.’s board of directors has determined that it has four audit committee financial experts serving on its audit committee. Christopher Ball, Kenneth Moore, George Steeves and Christopher Huskilson 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 Power & Utilities Corp. The SEC has indicated that the designation of Christopher Ball, Kenneth Moore, George Steeves and Christopher Huskilson 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, George Steeves and Christopher Huskilson 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.

CODE OF ETHICS

Algonquin Power & Utilities Corp. 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: apif@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 90) contained in Algonquin Power & Utilities Corp.'s Annual Information Form (dated March 31, 2010), 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, 2009 were pre-approved by the audit committee.

OFF-BALANCE SHEET ARRANGEMENTS

Algonquin Power & Utilities Corp. 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 Algonquin Power & Utilities Corp.'s financial condition, results of operations or cash flows.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The information provided under the heading "Contractual Obligations" (page 33) as set forth in Management's Discussion and Analysis for the fiscal year ended December 31, 2009, 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 88) identifying Algonquin Power & Utilities Corp.'s Audit Committee and confirming the independence of the Audit Committee as set forth in Algonquin Power & Utilities Corp.'s Annual Information Form (dated March 31, 2010), filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein.

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 Power & Utilities Corp. with respect to future events, based upon assumptions relating to, among others, the performance of Algonquin Power & Utilities Corp.'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 Power & Utilities Corp., its future plans and its dividends to shareholders. Statements containing expressions such as “outlook”, “believes”, “anticipates”, “continues”, “could”, “expect”, “may”, “will”, “project”, “estimates”, “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 Power & Utilities Corp. to make assumptions and involve inherent risks and uncertainties. Algonquin Power & Utilities Corp. cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that Algonquin Power & Utilities Corp.’s actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the continued 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 Management’s Discussion and Analysis for the fiscal year ended December 31, 2009, filed as Exhibit 99.3 to this annual report on Form 40-F and Algonquin Power & Utilities Corp.’s Annual Information Form (dated March 31, 2010), filed as Exhibit 99.1 to this annual report on Form 40-F. Algonquin Power & Utilities Corp. 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 Power & Utilities Corp. reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. Although Algonquin Power & Utilities Corp. 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 Power & Utilities Corp. 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.

UNDERTAKING

Algonquin Power & Utilities Corp. 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

Concurrently with the filing of this annual report on Form 40-F, Algonquin Power & Utilities Corp. has 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 Power & Utilities Corp. shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of Algonquin Power & Utilities Corp.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, 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 31, 2010

By: /s/ DAVID BRONICHESKI
Name: **David Bronicheski**
Title: **Chief Financial Officer**

EXHIBIT INDEX

Exhibit	Description
99.1	Annual Information Form for the year ended December 31, 2009
99.2	Audited Annual Financial Statements for the year ended December 31, 2009
99.3	Management's Discussion & Analysis for the year ended December 31, 2009
99.4	Reconciliation with United States Generally Accepted Accounting Principles for the year ended December 31, 2009
99.5	Consent Letter from KPMG LLP Chartered Accountants
99.6	Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
99.7	Certifications of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
99.8	Certifications of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.9	Certifications of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Exhibit 99.1

ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM

March 31, 2010

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SCHEDULE B
SCHEDULE C
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SCHEDULE E

In this Annual Information Form, all dollar figures are in Canadian dollars, unless otherwise indicated.

ALGONQUIN POWER & UTILITIES CORP

All information contained in this Annual Information Form (" **AIF**") concerning Algonquin Power & Utilities Corp. (" **APUC**") is presented as at March 31, 2010, unless otherwise specified. Schedules A, B, and C set out descriptions of the specific facilities and utilities of APUC (the "**Facilities**"). Schedule D contains the Audit Committee Charter of APUC and Schedule E sets out the forward-looking statement disclaimer applicable to this AIF.

STRUCTURE OF APUC

1.1 Name, Address and Incorporation

APUC 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 Hydrgoenique Incorporée – Hydrogenics Corporation and Hydrogenics Corporation – Corporation Hydrgenique, 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**") and changed its name to Algonquin Power & Utilities Corp. The head and principal office of the Corporation is located at 2845 Bristol Circle, Oakville, Ontario L6H 7H7.

APUC is continuing the business of Algonquin Power Income Fund (the " **Fund**"). On March 4, 2010, the board of Trustees of the Fund (the "**Trustees**") approved a resolution changing the name of the Fund from Algonquin Power Income Fund to Algonquin Power Co. (" **APCo**"). Trust units of APCo are APUC's principal holding. APCo is a limited purpose, unincorporated trust established under the laws of the Province of Ontario by a Declaration of Trust made as of September 8, 1977, as has been amended and restated.

Unless the context indicates otherwise, references in this AIF to "APUC" include, for reporting purposes only, the direct or indirect subsidiaries of APUC and partnership interests held by APUC and its subsidiaries. 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.

GENERAL DEVELOPMENT OF THE BUSINESS

2.1 General

On October 27, 2009, the Fund completed a corporate conversion transaction (the " **Unit Exchange Offer**") and a plan of arrangement (the "**Plan of Arrangement**") involving, among others, the Fund and 7188501 Canada Inc., Stuart Energy Systems Corporation and Hydrogenics Test Systems Inc. The Unit Exchange Offer provided the Fund's unitholders the opportunity to exchange their trust units of the Fund, on a one-for-one basis, for common shares of the existing corporation, Hydrogenics Corporation. Hydrogenics Corporation transferred all of its operations and existing shares to a new corporation pursuant to the Plan of Arrangement prior to completion of the Unit Exchange Offer. The name of Hydrogenics Corporation was changed to Algonquin Power & Utilities Corp. following closing of the transaction.

The transaction resulted in the unitholders of the Fund becoming shareholders of APUC, with no changes to the Fund's underlying business operations. Under the continuity of interest method of accounting, APUC's transfer of assets, liabilities and equity of the Fund are recorded at their net book

value in APUC's financial statements as at October 27, 2009. As a result of this transaction, certain terms such as shareholder/unitholder and dividend/distribution may be used interchangeably throughout this AIF. Prior to October 27, 2009, all distributions to unitholders were in the form of trust unit distributions.

Business Strategy

APUC's business strategy is to maximize long term shareholder value as a dividend paying, growth oriented corporation actively competing within its clearly defined business sectors. APUC is committed to delivering a total shareholder return comprised of a dividend augmented by capital appreciation arising through growth in earnings and dividends.

APUC produces stable earnings through a diversified portfolio of renewable energy and utility businesses owned and operated by its subsidiary entities. APUC currently conducts its operations primarily through two businesses: independent power and regulated water utilities, and intends to establish a third distinct business of regulated electric utilities. These businesses of APUC are herein referred to as the **"APUC Businesses"**.

Power Generation: The independent power business of APUC is carried on by APCo The business of APCo is to generate electrical energy through a diverse portfolio of clean, renewable power generation and thermal power generation facilities across North America. APCo develops and operates a diversified portfolio of electrical energy generation facilities. Within this business there are three distinct divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates APCo's hydroelectric and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division seeks to deliver continuing growth to APCo through the development of APCo's greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of organic growth opportunities within APCo's existing portfolio of renewable energy and thermal energy facilities. 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 involves building on APCo's expertise in the origination of greenfield renewable energy projects, building upon APCo's existing portfolio of assets for further growth, and capitalizing on new opportunities as they arise.

APCo's Renewable Energy division holds interests in 44 hydroelectric generating facilities located in Ontario (4), Québec (12), Newfoundland (1), New Brunswick (1) Alberta (1), New York State (13), New Hampshire (8), Vermont (1), Maine (2) and New Jersey (1) representing aggregate installed generating capacity of approximately 175 megawatts ("MW"). In addition, APCo's Renewable Energy division holds an equity interest in the St. Leon Facility (as defined below) located in Manitoba with installed capacity of approximately 99 MW. Approximately 75% of the installed capacity of APCo's renewable energy facilities operate under long term power purchase agreements ("**PPAs**") with major utilities and have an average remaining contract life of 16 years.

APCo's Thermal Energy division hold equity interests in one energy-from-waste facility in Ontario with an installed generating capacity of 10 MW, 4 landfill gas facilities in Tennessee and New Jersey with total installed generating capacity of 9 MW, 4 diesel generating facilities in Maine and New Brunswick with total installed generating capacity of 40 MW and 4 natural gas-fired cogeneration facilities in each of California, Connecticut, Ontario and New Jersey with an installed capacity of approximately 122 MW. In addition, APCo's Thermal Energy division owns partnership, share and debt interests in two biomass-fired generating facilities with combined installed capacity of approximately 43 MW located in Alberta and Québec. APCo's Thermal Energy division holds minority investments in

two natural gas/wood waste-fired generating facilities with joint installed capacity of approximately 172 MW located in northern Ontario. Approximately 85% of the combined installed generating capacity 396 MW of APCo's thermal energy facilities operate under long term PPAs with major utilities and have an 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.

Water Utilities: The regulated water utilities business of APUC is carried on by Liberty Water. In 2009, APUC branded all of its utilities under the Liberty Water brand. Liberty Water is committed to being the leading utility provider of safe, high quality and reliable water and wastewater services while providing stable and predictable earnings from its utility operations. Liberty Water delivers long term shareholder value by profitably owning and operating investor owned water and wastewater utilities providing safe, reliable transportation and delivery of water and wastewater treatment in its service areas. It is also focused on delivering continued growth in earnings by identifying opportunities which accretively expand its business portfolio.

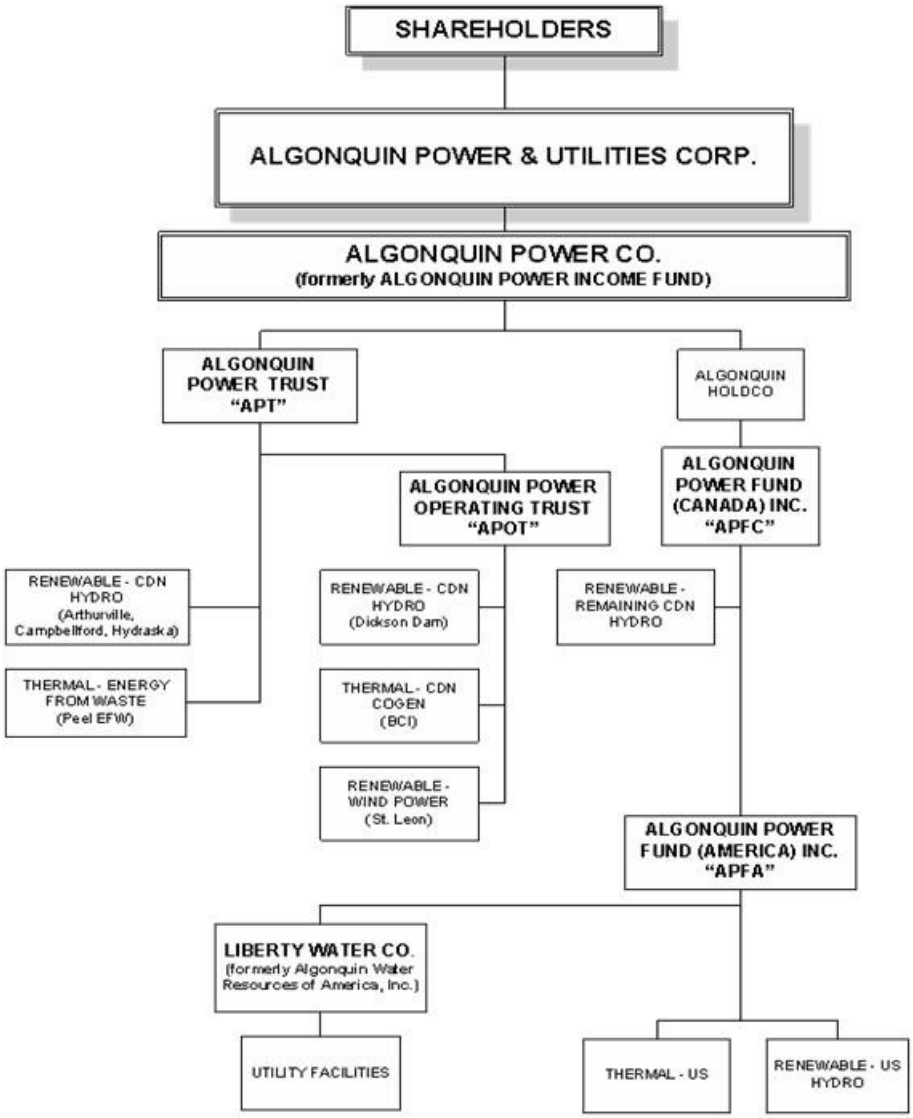
This APUC Business provides water and wastewater utility services through 19 owned and operated water distribution and wastewater utility systems in the United States. Liberty Water provides regulated water distribution and wastewater facilities in Arizona (8), Illinois (1), Missouri (3) and Texas (7). These utility operating companies are regulated investor-owned utilities subject to regulation, including rate regulation, by the public utility commissions of the states in which they operate. Detailed information on the water distribution and wastewater utility systems owned and operated by Liberty Water is set out in Schedule C.

Electrical Utilities: APUC has announced its plan to establish a third distinct business subsidiary focused on the provision of local regulated electrical generation and distribution utilities within a new business subsidiary to be called Liberty Electric. In this regard APUC announced plans to co-acquire an electrical generation and regulated distribution utility through a strategic partnership with Emera Inc. ("**Emera**") (see "*Significant Acquisitions in Fiscal 2009*").

2.2 Intercorporate Relationships

(a) Subsidiaries

APUC's principle holding is an investment in 100% of the issued and outstanding units of APCo In turn, the subsidiaries of APCo are aligned along different ownership chains. The operations of APCo include the ownership chains of APT, APOT, APFC, APFA, and the operations of Liberty Water. These are all defined and shown in the chart below. Non material holdings are not shown.



APUC beneficially owns, directly or indirectly 100% of the securities of 3793257 Canada Inc. (" **3793257**") and 3881105 Canada Inc. ("**3881105**"), corporations incorporated under the CBCA and 83.2% of APCo , an unincorporated open ended trust. APUC's subsidiary, 3881105, owns the remaining 16.8% of the outstanding trust units.

APUC owns 87.49125% of Loyalist Wind Project LP (**"Loyalist LP")**, an Ontario limited partnership which in turn was created to bid on a wind energy project. The remaining limited partners of Loyalist LP are an unrelated third party as to 12.49875% and the general partner, Loyalist Wind Project GP Inc. (**"Loyalist GP"**), an Ontario corporation, holding 0.01%.

APUC owns Liberty Electric Co., a Delaware corporation (" **Liberty Electric**"). Liberty Electric owns 50% of California Pacific Utilities Ventures, LLC, a California corporation ("**CPUV**"), which in turn owns California Pacific Electric Company, LLC, a California which intends to acquire the California-based electricity distribution and related generation assets of NV Energy, Inc. See "*Significant Acquisitions in 2009*".

APCo is the sole beneficiary of APT, which owns all the trust units of APOT. APT forms part of the APCo business unit and controls the entities that own some of the Canadian hydroelectric facilities, and the energy-from-waste facility (the **"EFW Facility"**) located in Brampton in the Regional Municipality of Peel, Ontario. APOT forms part of the APCo business unit and controls the entities that own the Canadian cogeneration facility located at Brampton, Ontario (the **"BCI Facility"**), the wind facility located at St. Leon, Manitoba (the **"St. Leon Facility"**), one hydroelectric facility in Alberta (the **"Dickson Dam Facility"**) and the Alberta biomass facility (the **"Valley Power Facility"**). The Fund also owns Algonquin Holdco Inc., an Ontario corporation, which owns APFC. APFC forms part of the APCo business unit and controls the entities that own the majority of the hydroelectric facilities in Canada. APFC also owns APFA, which forms part of the APCo business unit and is the top APCo entity in the United States. APFA own and controls the U.S. hydroelectric entities, and also controls the entities that own the U.S. cogeneration facilities known as Sanger and Windsor Locks as well as those that own the New Jersey (and Nashville) landfill gas assets. Finally, APFA owns Liberty Water Co. (formerly Algonquin Water Resources of America, Inc.), which controls all the entities that own the water and wastewater treatment facilities which form the Liberty Water business unit in Arizona, Texas, Missouri and Illinois.

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. 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. APFC was incorporated in Nova Scotia, and APFA and Liberty Water Co. are both Delaware corporations. A "**Trust Unit**" or "**Unit**" is a unit in a particular trust, with each unit representing an equal undivided beneficial interest in the trust.

The details of the subsidiaries and ownership interests in the various subsidiary legal entities and their jurisdictions of formation are described in greater detail below on the basis of the ownership chains. Information on ownership of the Facilities is also described below, and, as mentioned above, additional information on the Facilities named below is described in Schedules A, B and C. The interests held are 100% unless otherwise indicated.

APT Chain

APT forms part of the APCo business unit and indirectly owns the EFW Facility in the city of Brampton located in the Regional Municipality of Peel in the Province of Ontario by virtue of owning all the 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 is also associated with certain of the Canadian hydroelectric Facilities. It directly owns the hydroelectric Hydraska Facility located on the Yamaska River near the Town of St.-Hyacinthe and the Arthurville Facility near Ste-Raphaël, and owns both the general partnership and the limited partnership interests in Algonquin Power (Campbellford) Limited Partnership ("**Campbellford LP**"), an Ontario limited partnership which owns a 4 MW hydroelectric generation station on the Trent River near Campbellford, Ontario (the "**Campbellford Facility**"). It also holds 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 and the Côte Ste.-Catherine Facilities. 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'Investissement Éolienes Algonquin Power (" **Éolienes**"), a Canadian corporation. Éolienes indirectly owns the Gaspé Energy Project held by St. Ulrich Wind Energy Investments L.P. ("**St. Ulrich LP**"), a Québec limited partnership, through its ownership of the limited partnership of St. Ulrich LP, (Société en Commandite Algonquin (Éolienes), a Québec limited partnership, and its direct ownership of the general partner of St. Ulrich LP (Corporation D'Investissements Éolienes St-Laurent Inc., a Québec corporation).

APOT Chain

APOT forms part of the APCo business unit. The APOT entities that own the BCI Facility are 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 all the limited partnership units in the partnership. BCI is an Ontario corporation and is owned by APOT.

The APOT entity that owns the St. Leon Facility is St. Leon Wind Energy LP (" **St. Leon LP**"). It is owned 21.9% by the general partner, St. Leon Wind Energy GP Inc. ("**St. Leon GP**"), 69.89% by St. Leon Wind Energy Trust (" **St. Leon Trust**") and 8.2% by AirSource Power Fund I LP ("**AirSource**"). St. Leon LP has issued 100 Class B limited partnership units. Affiliates of APMI hold 60% of these outstanding units and the remaining 40% are owned by third party investors. 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. 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. AirSource and AAP LP limited partnerships were formed in Manitoba and Ontario, respectively. APOT is also the sole limited partner in St. Leon II Wind Energy LP ("**St. Leon II LP**"), a Manitoba partnership, the general partner of which is St. Leon II Wind Energy GP Inc. ("**St. Leon II GP**") which is also owned by APOT.

APOT also owns Loyalist GP, the general partner for Loyalist LP. As noted above, APUC is the majority owner of Loyalist LP.

APOT has two ownership interests in Alberta. First, it is the beneficial owner of the Dickson Dam Facility. Second, it 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 Valley Power Facility. APOT directly holds a further 49.9995% limited partnership interest in Valley Power LP.

APFC Chain

APFC forms part of the APCo business unit. The Canadian hydroelectric facilities in which APFC holds direct or indirect interests are in Ontario and Québec. 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 as to 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 (Rattle Brook) Partnership, a Newfoundland partnership that owns the Rattlebrook Facility.

APFA Chain

APFA forms part of the APCo business unit. APFA owns the entities that own the U.S. cogeneration Facilities of the Sanger, Windsor Locks and Crossroads Facilities, and also those that own the New Jersey (and Nashville) landfill gas assets and American hydroelectric Facilities. Sanger and Windsor Locks are owned by, respectively, Algonquin Power Sanger LLC ("**Sanger LLC**"), a California limited liability company, and Algonquin Windsor Locks LLC, a Connecticut limited liability company, both of which are owned 100% by APFA. Sanger LLC directly owns 100% of Dyna Fibres Inc. a California corporation that operates a hydro-mulch business at the Sanger Facility site. The Crossroads Facility is owned by KMS Crossroads, LLC, a Delaware limited liability corporation.

APFA indirectly owns numerous hydroelectric facilities through majority interests ranging from 98% to 99.99% in the direct subsidiaries described below, with Algonquin Power Fund (America) Holdco Inc. ("**Algonquin America Holdco**"), a Delaware corporation owned by APFA, holding the remaining interests. The New York general partnerships Burt Dam Power Company and Hollow Dam Power Company own the Burt Dam and Hollow Dam Facilities, respectively. The Vermont partnership Moretown Hydro Energy Company owns the Moretown Facility. The New Hampshire corporation, Lakeport Hydroelectric Corporation, owns the Lakeport Facility, and 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. The New Hampshire limited liability company Clement Dam Hydroelectric, LLC owns the Clement Dam Facility. The Franklin, Beaver Falls and Milton Facilities are owned by, respectively, Franklin Power LLC, a New Hampshire company, Algonquin Power (Beaver Falls) LLC, a Delaware corporation, and SFR Hydro Corporation, a New Hampshire company. All of these companies are 100% owned by APFA. The Otter Creek and Kings Falls Facilities are owned by Tug Hill Energy, Inc. a New York corporation, which is owned by Court Street Investments, Inc. ("**Court Street**"), a Massachusetts corporation, and which in turn is owned 100% by APFC. Court Street also 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 Algonquin America Holdco 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 Algonquin America Holdco. The Lochmere Facility is owned by the Indiana general partnership HDI Associates I, which is held 1% by Algonquin American Holdco and 99% by APFA.

APFA, in January 2010, 100% acquired two entities, now known as 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 registered in Maine. APFA also 100% owns Algonquin Energy Services Inc., a Delaware corporation ("**AES**"). On February 4, 2010, AES acquired a number of load supply and energy procurement contracts in northern Maine and the Independent System Operator New England ("**ISO-NE**") market (the "**Energy Services Business**"). See "*Outlook for Fiscal 2010*" and "*Energy Marketing Business*" in "*Description of the Business*".

In addition, APFA owns 100% of Algonquin Power Acquisition Inc. a Delaware corporation that was incorporated as an acquisition vehicle for proposed acquisitions by Algonquin in the United States. It currently has no assets.

The landfill gas assets in New Jersey are owned by MM Hackensack LLC and NEO Hackensack LLC, both Delaware corporations, and Meadowlands Gas Treaters LLC ("**MGT**"), a New Jersey company. The Nashville landfill gas assets in Tennessee are owned by MM Nashville Energy LLC and NEO Nashville LLC, both Delaware corporations. MM Hackensack LLC and MM Nashville Energy LLC own generating facilities, and are owned by Algonquin Power – Cambrian Pacific Genco LLC ("**Algonquin-Cambrian**"), a Delaware corporation, which is 98% owned by Algonquin Power Biogas LLC ("**Algonquin Biogas**"), a Delaware corporation, and which in turn is 100% owned by APFA. APFA also is the owner of Across America LFG LLC, a Delaware corporation, which is the entity that owns NEO Hackensack and NEO Nashville LLC. MGT holds the gas rights relating to the Kearny landfill, and it is majority owned by Algonquin Biogas. Algonquin Power Systems (LFG) LLC is a New Hampshire corporation owned 100% by Algonquin – Cambrian established to service the landfill gas assets of APCo.

Liberty Water Chain

Liberty Water Co. forms the top of the Liberty Water chain and indirectly owns the Facilities of the Regulated Water Utilities Business, in each case through a 100% wholly-owned subsidiary, with the exception of the Entrada Del Oro Sewer Company, Inc. (**"Entrada"**) in which it currently operates and holds a beneficial interest in the shares of the company pending regulatory approval of its acquisition by Liberty Water Co. All of these 100% wholly-owned subsidiaries (except Northwest Sewer, Inc,) are currently conducting business as "Liberty Water"; 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; and Algonquin Water Resources of Texas, LLC, a Texas limited liability company, owns water and water treatment assets at the resorts of Galveston, Holly Lake Ranch, Hill County, Piney Shores and The Villages (also known as "Big Eddy"). In Missouri, Algonquin Water Resources of Missouri, LLC, a Missouri limited liability company, owns assets associated with the Holiday Hills, Ozark Mountain and Timber Creek resorts. In Illinois, Algonquin Water Resources of Illinois, LLC, an Illinois limited liability company owns assets for the Fox River resort. All water and wastewater utilities are operated under the Liberty Water brand.

In addition, Algonquin Water Services LLC (**"Water Services"**) is a company established to manage and operate water distribution and wastewater treatment facilities in Arizona and Texas. It is an Arizona limited liability company owned 99% by New Spring Acquisition Partnership, an Ontario partnership, which in turn is owned 50% by APCo Algonquin Environmental Services LLC, a Delaware limited liability company owned 100% by AWRA, was also established to service the Utility Services business unit.

(b) Other Interests in Energy Related Developments

APUC 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 Commandité ("**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, APUC 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. The LSR Subordinate Note was acquired by the Fund on April 17, 1998. Finally, APCo is entitled to revenues generated by the Trafalgar Facilities by virtue of being the owner of the Trafalgar Class B Note, subject to the bankruptcy action, all as defined and described in *"Legal Proceedings"* below.

2.3 Three Year History

(a) Developments in Fiscal 2007

On February 13, 2007, Southern Sunrise Water Company Inc. and Northern Sunrise Water Company Inc., both indirect wholly-owned subsidiaries of Liberty Water Co., completed the acquisition of the assets and regulatory licences related to the provision of utility services to approximately 1,500 water distribution customers located near the Town of Sierra Vista, Arizona. The aggregate cost for completing the acquisition of the assets related to such services and completing the regulatory hearings necessary to approve the transaction was US $1.0 million.

On March 16, 2007, the Fund, through APT, commenced a formal take-over bid for all of the outstanding trust units of Clean Power Income Fund ("**Clean Power**") in exchange for Trust Units on a one for 0.6152 basis plus a contingent value receipt. In addition, the Fund made an offer to acquire all of the outstanding 6.75% convertible debentures issued by Clean Power in exchange for convertible

debentures of the Fund. On April 19, 2007, the Fund withdrew its offer, following the announcement by the board of trustees of Clean Power that it had terminated its support for the previous offers pursuant to the support agreement dated February 25, 2007 between Clean Power, Clean Power Operating Trust, the Fund and APT (the "**Support Agreement**"). In connection with the termination of the Support Agreement, a termination fee of $1.75 million was payable to the Fund. In addition, the Fund was entitled to reimbursement of its expenses up to a maximum of $0.85 million from Clean Power.

On September 18, 2007, the Fund's Renewable Energy division's St. Leon Facility achieved commercial operation. Vestas-Canadian Wind Technology, Inc. ("**Vestas**") was the prime contractor in charge of the turn-key construction contract dated November 12, 2004 (the " **Vestas Contract**") to complete the St. Leon Facility. The commercial operation date marked the commencement of a five year warranty period with Vestas. The declaration of commercial operation pursuant to the Vestas Contract was pending agreement on the process for resolution of certain outstanding construction-related issues. The St. Leon Facility achieved commercial operation status under the PPA with Manitoba Hydro as of June 17, 2006.

On December 11, 2007, the Fund's Thermal Energy division announced the successful installation of the new turbine at the Sanger Facility, following the major re-powering project which commenced in October 2006. The start-up was completed on time and on budget with a total cost of approximately $25 million (US$23 million). As a result of the retrofit, the Sanger Facility has approximately 14MW of generating capacity in excess of its current PPA requirements. APCo's Thermal Energy division is currently reviewing its options with regards to securing a market for the additional capacity. Such capacity could be sold to its existing customer or to the market.

On December 21, 2007, the Fund's Thermal Energy division's Algonquin - Cambrian completed the sale of six landfill gas generating stations and other related landfill gas assets to Fortistar LLC, for a purchase price of approximately $11.3 million (US$11.3 million). The six facilities represented approximately 18MW of installed generating capacity with five facilities located in California and the remaining facility located in New Hampshire.

On December 28, 2007, based on a review of its smaller hydroelectric generating facilities, the Fund's Renewable Energy division completed the sale of six facilities in the New England region for proceeds of approximately $1.5 million. The six facilities represented approximately 3MW of installed generating capacity with five facilities located in New Hampshire and the remaining facility located in Vermont.

The decision to sell both the landfill gas facilities and the smaller hydroelectric facilities was made since the facilities no longer fit the Fund's preferred asset profile and were no longer considered strategic to the ongoing operations of the Fund.

In December 2007, two projects totalling 165MW submitted by the Fund's Development division were selected to proceed to the next phase in Manitoba Hydro's "Request for Proposal 025089 – Potential Purchase of Output from Manitoba's Wind Powered Electrical Generation Facilities". The two projects consist of the 99MW Glenwood Wind Energy Project ("**Glenwood**") located in the Rural Municipality of Glenwood, near the Town of Souris, Manitoba, and a 66MW expansion of the St. Leon Facility. These two proposals were ultimately not designated for final selection. It is anticipated another provincial proposal will be released in 2010 and APCo believes the original Glenwood and St. Leon expansion proposals will be re-examined by the Province of Manitoba as additional options to fulfill its publicly stated commitment to expand the use of wind and other sources of renewable energy in Manitoba.

(b) Developments in Fiscal 2008

In 2008, the Fund accomplished several major initiatives that have strengthened its operational performance and financial position.

On January 16, 2008, the Fund, renewed its combined $175.0 million senior secured revolving operating and acquisition credit facilities (the **"Senior Credit Facility"**) with its Canadian bank syndicate. Under terms of the renewal, the Senior Credit Facility is extended for a three year term with a maturity date of January 14, 2011. The renewal included improved pricing and other terms as well as an accordion feature that, subject to certain conditions, allows the Senior Credit Facility to increase to $225.0 million to accommodate future growth and acquisitions. At the same time, the bank syndicate was expanded from three to four financial institutions, all of which are Canadian Schedule I banks with a credit rating of A or higher. As a result of the renewal, the Fund does not have any near term credit maturity exposures. By the end of 2008, the Fund had exercised a portion of the accordion feature, resulting in total committed and available Facilities of $192.8 million.

In June 2008, the Fund's Thermal Energy division's BCI Facility was commissioned and operational. The project involved diverting the existing steam produced by the EFW Facility to a nearby recycled paper board manufacturing mill that requires approximately 90,000 pounds of steam per hour in its manufacturing activities. The Fund's Thermal Energy division established the BCI Facility to operate the required facilities to supply steam produced through normal operations at the EFW Facility to this mill.

On June 27, 2008, the Fund entered into a business combination agreement (the **"Business Combination Agreement"**) with Highground Capital Corporation ("**Highground**") and CJIG Management Inc. (" **CJIG**"), the manager of Highground and a related party of the Fund controlled by the shareholders of APMI. Pursuant to the Business Combination Agreement, CJIG acquired all of the issued and outstanding common shares of Highground, and the Fund issued approximately 3.5 million Trust Units at approximately $7.69 per Trust Unit. The trading price of the Trust Units at the time of issue was $7.41. Of these Trust Units, approximately 3.1 million Trust Units were received by Highground shareholders as part of the Business Combination Agreement, with the remaining Trust Units being retained by CJIG. The Fund recorded the Trust Units issued at the estimated fair value of the assets to be liquidated by Highground which, net of transaction costs of $0.8 million, resulted in proceeds of the Trust Units being recorded at a value of $26.2 million. In connection with this transaction, the Fund received: (a) net cash in an amount of $20.6 million; (b) the return of notes, having an aggregate face value of approximately $4.8 million, that were issued by the Fund affiliates related to its St. Leon and BCI Facilities; and (c) a note receivable of $0.8 million related to a hydroelectric facility in Ontario.

The final consideration for the Trust Units is dependent on the proceeds realized from the liquidation of certain Highground investments. The Fund's final consideration will be equal to the lesser of (a) $27.0 million plus 50% of the amount, if any, of the value of the assets formerly owned by Highground after payment of the transaction costs that exceeds $27.0 million and (b) the value of all of the assets formerly owned by Highground after payment of the transaction costs. The value of any non-cash securities received by the Fund will be determined through negotiation between the Trustees and CJIG. The remaining investments, formerly held by Highground, currently consist of primarily non-liquid debt assets having a book value of approximately $3.2 million. The payments on these securities are current and the debt matures over the next three years. The Fund is entitled to 50% of the ultimate proceeds from these investments, after certain adjustments for transaction costs.

On October 20, 2008, the Trustees approved a strategic plan that would align the Fund's business structure with current market conditions and expected growth prospects. In order to strengthen the Fund's financial position and support its strategic growth initiatives, the Fund established a sustainable cash distribution level consistent with the Fund's growth prospects. To further support its strategic plan, the Fund realigned its operations into the two major business units: Power Generation & Development, and Utility Services.

By the end of 2008, APUC completed the majority of its major capital program in the Liberty Water business unit. Liberty Water initiated rate cases at several utilities. See "*Liberty Water – Rate Cases*".

(c) Developments in Fiscal 2009

On October 27, 2009, APUC completed its conversion from an income trust to a corporation. The conversion was completed through a series of transactions more fully described below.

On October 27, 2009 the Fund's unitholders exchanged 100% of the outstanding trust units of the Fund for Common Shares of APUC (formerly Hydrogenics Corporation or Hydrogenics), an existing corporation. Immediately prior to the Unit Exchange Offer, Hydrogenics, under a Plan of Arrangement, transferred all of its operations and substantially all of its assets and liabilities to New Hydrogenics. The pre-existing publicly traded shares of Hydrogenics were contemporaneously redeemed for shares of New Hydrogenics and thus the pre-existing publicly traded shares of Hydrogenics no longer exist.

The transaction resulted in the unitholders of the Fund holding their interest in the Fund as shareholders of APUC. Excluding Common Shares issued under the CD Exchange Offer (as defined and described below), the number of Common Shares of APUC outstanding immediately after completion of the Unit Exchange Offer was exactly the same as the number of the Fund's trust units outstanding immediately before the Unit Exchange Offer.

The Unit Exchange Offer was accounted for as a change in business form using the continuity of interests method of accounting. Under this method of accounting, the transfer of the assets, liabilities and equity of the Fund are recorded at their net book values in the financial statements of APUC as at October 27, 2009, the effective date of the transaction. As a result, APUC is required to be accounted for as though it were a continuation of the Fund but with its capital reflecting the exchange of Common Shares for trust units. For the periods reported up to the effective date of the Unit Exchange Offer all payments to unitholders were in the form of trust unit distributions and after that date all payments to shareholders were in the form of dividends.

APUC paid New Hydrogenics $10,813 and has accrued an additional amount of $494 as a final closing adjustment. As a result of the Unit Exchange Offer, together with substantively enacted changes in tax rates in December 2009, APUC recognized a future income tax asset of $60,014 and a deferred credit in relation to this asset of $49,879 as at December 31, 2009. For accounting purposes the deferred credit is recorded as a credit to tax expense when the future tax assets are realized.

On December 21 2009, the Board of Directors of APUC (the " **Board**") reached agreement with the shareholders of Algonquin Power Management Inc. ("**APMI**") to internalize all management functions of the Fund which were provided by APMI. APUC will acquire the interest previously held by APMI in the management services agreement, with consideration to be paid in the form of issuance of 1,158,748 Common Shares (the "**Shares**"). The consideration payable in the form of Shares is subject to regulatory and shareholder approval. An independent advisor retained by the Board concluded that the consideration to be paid by APUC pursuant to the transaction is fair, from a financial point of view. The expense has been measured at $4,693 using a price for each share of $4.03, the adjusted closing market price on December 21 2009, the date the agreement was ratified.

Effective as of December 21, 2009, Mr. Ian Robertson assumed overall responsibility for APUC's operations as Chief Executive Officer and will be invited to join the Board. Mr. Robertson previously held the position of Executive Director, Business Development with the Fund. Mr. Chris Jarratt has joined the Strategy Development Committee where he is co-directing the development of strategy with APUC management and will be invited to join the Board in the role of Vice Chairman. Mr. David Kerr has been retained to provide transitional services to APUC.

In accordance with the policies of the Toronto Stock Exchange (" **TSX**"), approval of the issuance of the Shares will be sought from shareholders at the next annual general meeting. The beneficial interest in the Shares of those individuals who are continuing in management roles with APUC is intended to create and maintain alignment with the interests of APUC's shareholders.

During the second quarter of 2009, the Trustees also announced that, in conjunction with the Unit Exchange Offer, holders of the Fund's convertible debentures would be provided the opportunity to exchange their debentures for new debentures of APUC (the "**CD Exchange Offer**").

Contemporaneously with the Unit Exchange Offer on October 27, 2009, holders of the Fund's convertible debentures exchanged their convertible debentures for convertible debentures or Common Shares of APUC resulting in the Fund's debentureholders becoming debentureholders and shareholders of APUC and the maturity date of the Series 1 Debentures being extended from 2011 to 2014.

Pursuant to the CD Exchange Offer, $63,755 of the outstanding Series 1 Debentures were exchanged for Series 1A Debentures in a principal amount of $66,943, and $21,209 of the outstanding Series 1 Debentures were exchanged for 6,607,027 Common Shares. In addition, all of the outstanding Series 2 Debentures were exchanged for Series 2A Debentures in a principal amount of $59,967. (See: *Capital Structure - Convertible Debentures*).

On December 2, 2009, APUC completed, on a bought deal basis, an offering of 5,980,000 common shares at $3.35 per Common Share for gross proceeds of $20,033 and an offering for $55,000 principal amount of 7% convertible unsecured subordinated debentures due June 30, 2017 (the "**Series 3 Debentures**"). The underwriters of the offering also exercised in full an over-allotment option to purchase an additional 897,000 common shares and $8,250 principal amount of Series 3 Debentures on the same terms. As a result of the closing of the main offering and the over-allotment option, APUC raised an aggregate of $82,606 in net proceeds after underwriting expenses and before additional issuance costs ($86,288 in gross proceeds).

The Series 3 Debentures bear interest at a rate of 7% per annum payable semi-annually in arrears on the last day of June and December in each year commencing on June 30, 2010, and will mature on June 30, 2017. The Series 3 Debentures will be convertible at the holder's option into common shares of APUC at a conversion price of $4.20 per Common Share (See: *Capital Structure - Convertible Debentures*).

During the 2009 fiscal year, the 18 individual water and waste water utilities owned by APUC adopted the single consolidated brand of "Liberty Water" with the objective of improving the quality and consistency of services provided to the organization's approximately 70,000 regulated water/wastewater utility customers through updated web customer service, paperless electronic billing and expanded service hours. A secondary objective of aggregating APUC's water utility operations under the Liberty Water brand is to support the transparent analysis of APUC's water utility business as compared to other publicly traded US based water utility businesses.

At the annual general meeting of unitholders of the Fund held on July 27, 2009, in addition to the re-election of existing trustees, Mr. Christopher Huskilson was elected as a trustee of the Fund. As part of the Unit Exchange Offer, the Trustees also became directors of APUC (the "Directors"). The Board and management of APUC believe that Mr. Huskilson's utility and power experience will make a strong addition to the Board and will support APUC's long term strategy and corporate governance activities. As part of the management internalization process, Mr. Robertson and Mr. Jarratt have been invited to join the Board.

APUC's slate of proposed Directors in respect of the election of Directors by shareholders at the annual general meeting shall continue to be determined by the Directors in accordance with APUC's governance policies and procedures. It is contemplated that Mr. Robertson and Mr. Jarratt will stand for election as Directors at the next annual general meeting of shareholders.

(d) Outlook for Fiscal 2010

On January 12, 2010, APCo completed the acquisition of 36.8MW of electrical generating assets (the " **Tinker Assets**") that was announced on November 10, 2009. The Tinker Assets are located in New Brunswick and Maine and were purchased after satisfying the conditions of the acquisition, including regulatory approval.

Through the purchase of shares and assets, APCo has acquired three hydroelectric generating stations, the 34.5MW Tinker Hydro, a 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, Caribou Hydro, a 0.9MW run-of-river hydroelectric generating facility located in Northern Maine and Squa Pan Hydro, a 1.4MW run-of-river hydroelectric generating facility located in Northern Maine.

APCo has also acquired five thermal generating facilities with a rated capacity of 40MW in Northern Maine and New Brunswick utilized for installed reserve capacity, not continuous generation, 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, ISO-NE).

In connection with the acquisition of the Tinker Assets, on February 4, 2010, APCo acquired the Energy Services Business which will market the energy generated from the Tinker Assets. It is anticipated that the majority of the energy sold by the Energy Services Business will be supplied through generation from the Tinker Assets, based on historical long term average levels of hydroelectric energy generation of these facilities but additional energy would need to be purchased from other sources. The Energy Services Business 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.

The Energy Services Business consists of a series of short-term energy supply agreements which generally will expire within the next 14 months. 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.

The hydroelectric and thermal generation assets offer capacity to support the energy services obligations in northern Maine. The acquisition improves hydrologic diversification through a new geographical area to the APCo generation portfolio and builds APCo's Eastern Canadian generating presence.

APCo's Renewable Energy division is expected to perform at or below long term average resource conditions in the first quarter of 2010 with the exception of the Quebec and New England regions where APCo anticipates at or above long term average resource conditions. APCo is expecting an improvement in weighted average energy rates at its U.S. renewable facilities as compared to the rates experienced in the first quarter of 2009. The 2010 first quarter results will include results from the acquisition of three hydroelectric generating stations with a capacity of 36.8 MW located in New Brunswick and Maine. The energy produced by these facilities will be shown as the Maritime Region.

APCo Thermal Energy division's EFW Facility is expected to operate below APCo's expectations during the first quarter of 2010 due to an unplanned outage in January 2010 related to problems with boiler tubes. The facility is expected to be operational in spring 2010 once the boiler tube issues are resolved. APCo is accelerating capital maintenance originally planned for the second and third quarters of 2010 during this outage which should allow the Facility to make up some of the income expected to be lost in the first quarter in the remainder of 2010.

APCo Thermal Energy division's Sanger Facility is expected to operate at or above APCo's expectations for the first quarter of 2010 in line with 2009 results. APCo's power development team will continue to pursue new opportunities for power generation projects in both Canada and the U.S. APCo will continue to focus on cost containment and productivity improvement measures that will maximize margins and EBITDA throughout 2010.

APCo Thermal Energy division's Windsor Locks Facility is expected to operate at or above APCo's expectations for the first quarter of 2010 and in line with 2009 results. In the second quarter APCo expects Windsor Locks to perform in line with 2009 results until the PPA with Connecticut Light & Power ("**CL&P**") expires in April 2010 after which APCo expects to be able to sell between 10MW and 40MW of electrical capacity to a local utility or provide ancillary services such as "spinning reserves" to the ISO-NE. For a more detailed description of the options and expected impact see "*Windsor Locks Facility – Windsor Locks, Connecticut"* under "*Material Facilities*" in the section entitled "*Cogeneration*" below.

Liberty Water has ongoing rate cases at a number of its utilities and will continue to process these rate cases throughout 2010. See "*Liberty Water – Rate Cases*" for further discussion of the status of these rate cases. An exact determination of increased revenues from all rate case applications is not possible at this time as the timing of conclusion to the rate cases and the final decision on rate increases are determined by the regulator. As a result of delays in the progress of rate cases through the regulatory processes, Liberty Water now anticipates that approximately $7 million of additional revenue from rate cases will be achieved in 2010 but the full annualized increase in revenues determined through the rate case processes is expected to be achieved in 2011.

The regulatory reviews of the rates and tariffs for these Facilities are expected to conclude in early 2010, with the new rates and tariffs implemented and/or going into effect in the first half of 2010, depending on the state in which the relevant facility operates. The Liberty Water business unit will also continue to consider accretive water and wastewater utility acquisition opportunities, as well as acquisitions in other regulated utilities, such as electricity distribution.

With respect to growth, Liberty Water is expecting limited organic expansion due to the slowdown in the U.S. housing market. Liberty Water expects to deliver growth through its acquisition.in March, 2010 of an additional water distribution and wastewater collection system. Located near Galveston, Texas, the Galveston System provides water distribution and waste water collection to over 250 connections.

2.4 Significant Acquisitions in Fiscal 2009

On April 23, 2009, APUC announced that it plans to co-acquire an electrical generation and regulated distribution utility through a strategic partnership with Emera. APUC and Emera will each own 50% of the newly formed California Pacific Electric Company, LLC ("**Calpeco**"), a California limited liability company. Calpeco intends to acquire the California-based electricity distribution and related generation assets (the "**California Utility**") of NV Energy, Inc. (" **NV Energy**") for the purchase price of approximately US $116 million, subject to certain working capital and other closing adjustments, as outlined in the asset purchase agreement by and between Sierra Pacific Power Company d/b/a NV Energy and Calpeco dated April 22, 2009 (the "**Purchase Agreement**"). APUC and Emera will jointly own and operate the California Utility through Calpeco. The California Utility currently provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. In October 2009, an application was filed with the California Public Utilities Commission requesting approval of the transaction in which NV Energy has agreed to sell its California electric distribution and generation assets to Calpeco. The transaction is subject to state and federal regulatory approval which is expected to occur in the latter half of 2010.

As an element of the California Utility strategic partnership, pursuant to a subscription and unitholder agreement dated April 22, 2009 (the "**Subscription Agreement**"), Emera has also agreed to a conditional treasury subscription of approximately 8.5 million trust units of the Fund at a price of $3.25 per unit. Subsequent to the completion of the Unit Exchange Offer, the Subscription Agreement was amended to reflect a subscription of Common Shares rather than trust units of the Fund. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of the California Utility.

For complete details on the Purchase Agreement and the Subscription Agreement, reference should be made to the documents as filed on SEDAR at www.sedar.com.

DESCRIPTION OF THE BUSINESS

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

Power Generation Regulatory Regimes

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. In the late 1980's and early 1990's, British Columbia, Alberta, Ontario, Québec, Nova Scotia and Newfoundland (and later Saskatchewan and Manitoba) established programs to actively seek independently produced power. By the late 1990's, many of the large utilities started the process of restructuring the energy market. To date, British Columbia, Alberta, and Ontario have made progress on restructuring and introducing competition into the energy market.

"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. In April 1997, Natural Resources Canada announced that, as part of the federal Green Power Procurement program, the federal government entered into an agreement to purchase up to 13,100 megawatt hours (**"MW-hrs"**) per year of Green Power from a utility to supply electricity to buildings owned by Natural Resources Canada and Environment Canada. Further, at that time, the Minister of the Environment announced that Environment Canada would be greening up to 20% of its nation-wide electrical consumption before 2010 to assist the growth of the Green Power sector while reducing the greenhouse gas emissions caused by the Department's use of electricity.

The federal government in its 2001 federal budget established the Wind Power Production Incentive (**"WPPI"**) with a goal of stimulating 1,000 MW of new wind energy over a five year period. In 2005, the target was expanded to 4,000 MW. An incentive payment of $10 per MW-Hr of production for the first ten years of operations was made available to eligible projects commissioned before April 1, 2010. In 2007, a new Renewable Power Production Incentive program (**"RPPI"**) called "ecoEnergy for Renewable Power" replaced WPPI and was created to stimulate up to 14.3 terawatt hours of other new renewable energy. The RPPI provides for an incentive of $10 per MW-Hr of production for the first ten years of operations for eligible projects commissioned after April 1, 2007 and before March 31, 2011. Eligible technologies include waterpower, advanced, innovative and highly efficient biomass, combustion technologies using biogas and other renewable technologies.

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. Public Utilities Regulatory Policies Act (**"PURPA"**). FERC, pursuant to the PURPA legislation, mandates the development of policies by state utility commissions and utilities themselves that enable private producers to build power facilities. The key policy issue was the development of long term PPAs with fixed, long-term power purchase rates. The long-term rates were based on projections of the utilities' Avoided Costs. "**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. Today, due to market forces and economic changes, many of these long-term agreements are priced far above current market rates. While these higher costs are burdensome to the utilities, most have recognized these as costs incurred prior to deregulation that can no longer be paid by the rate base due to changes to various factors.

On February 2, 2006, PURPA issued revised rules, *Revised Regulations Governing Small Power Production and Cogeneration Facilities* , Order No. 671, 114 FERC 61,102 (2006). Further regulations were also issued to clarify the regulations and became effective on April 20, 2006. In order to comply with the new regulations, in June of 2006, APUC filed with FERC a notification of holding company status for each direct and indirect subsidiary company of APUC. Based on an initial review of the regulations, APFC may be impacted by the revised rules. APUC is currently investigating the option of filing an exemption or waiver with FERC for APFC.

The key regulations that impact APUC are:

(a) Any type of Qualifying Facility that exists but has never filed a self-certification (or obtained an order certifying it as a Qualifying Facility) must file a self-certification (or petition for an order) within 60 days of Order No. 671. Self-certification documents were filed for all affected APUC Facilities in compliance this regulation.

(b) Any cogeneration Qualifying Facility, any small power production Qualifying Facility less than 30 MW, and any geothermal small power production Qualifying Facility, is now subject to rate regulation under Section 205 and 206 of the *Federal Power Act*. However, sales of energy or capacity

made by Qualifying Facilities 20 MW or smaller, or made pursuant to a contract executed on or before March 4, 2006, or made pursuant to a state regulatory authority's implementation of PURPA are exempt from scrutiny under sections 205 and 206. If this exception does not apply, then these Qualifying Facilities must make a rate filing under section 205 of the Federal Power Act in order to be eligible to sell electricity. Rate filings were required to be made on or before the effective date of Order 671, which was March 4, 2006. All relevant APUC Facilities had PPAs in place predating this section of the new FERC regulations and as such have not been impacted.

The Obama-Biden *New Energy for America Plan* supports 10% of electricity in the United Sates being generated from renewable sources by 2012 and 25% by 2025. The demand for additional renewable power is also expected to increase from the desire by various government entities to increase infrastructure spending.

Water Utility Services Regulatory Regimes

The Global Water Services Market

The global market for water supply and treatment equipment and services has been growing rapidly over the last decade and currently constitutes over a third of the global market for environmental products and services. The trend to market pricing for water services, combined with the growing private sector participation in water and wastewater utilities, has generated an opportunity for private capital to participate in water services markets. The opportunity is enhanced by increasingly stringent potable water quality standards, decreasing supplies of naturally clean water in populated areas and enforcement of environmental regulations.

The United States, Western Europe and Japan represent over 80% of the total market for water services and equipment. These markets are generally mature with an average growth of approximately 3 to 4% consistent with the growth in population. The largest participants in serving the global water and wastewater industry are based in the United States, France, Britain, Japan and Germany.

United States Water Services Industry

The ownership of water assets and the provision of water and wastewater services around the world, including the United States, remain primarily concentrated in the public sector, typically at the municipal or community level. Rates charged by such utilities are determined in the discretion of the municipality on the premise that such services are provided at cost.

Notwithstanding the foregoing, approximately 55 million Americans living in smaller communities are served by approximately 60,000 privately owned water utilities and 5,500 privately owned wastewater utilities. These utility operating companies are investor-owned utilities subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions typically have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities owned by Liberty Water operate under cost-of-service regulation as administered by these state authorities. These 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 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%.

In the continental United States, water supplies and resources for approximately one-third of the landmass are considered endangered. The southwest United States is particularly susceptible to the effects of groundwater and surface-water withdrawals, precipitation lost through evaporation, lack of industrial water recycling and extremes of temperatures.

The connection between the water delivery and wastewater collection and reclamation industries is becoming intertwined with the advent of stronger re-use requirements and continuing evolution in water rights. The industry and regulators appear now to agree that high quality reclaimed water from wastewater treatment and potable groundwater are integrally connected. In many jurisdictions in the United States, reclaimed water is being used in place of potable or virgin groundwater for commercial and irrigation applications and recharged into ground aquifers for future withdrawal and re-introduction into the potable water systems by water delivery utilities. The wastewater treatment utilities are awarded credits for such recharge and the water delivery utilities utilize such credits to gain access to additional groundwater resources for pumping and delivering water to new customers. These credits may also be sold to other users instead of being utilized by the utility.

The global market for water and wastewater services and equipment is large and growing. There are a large number of private water and wastewater companies in the United States and a large concentration of these utilities is located in the high growth areas of the arid southwestern States.

Generally, investor-owned 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 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 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 rate payers 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.

3.2 General Description of the Businesses of the Subsidiaries of APUC:

Production Method, Principal Markets, Distribution Methods and Material Facilities

(a) 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 headpond.

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 of APCo's Renewable Energy division's hydroelectric facilities 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.

Alberta

Electrical power generators in Alberta are regulated by the *Electric Utilities Act (Alberta)* (the "**EU Act**"). The EU Act permits the development of a competitive marketplace for electricity in Alberta. The EU Act also created the Alberta Power Pool through which all electrical power must be traded in Alberta.

The EU Act was amended to separate generation, transmission and distribution of electrical power in Alberta for regulatory purposes. The amendments to the EU Act and corresponding regulations in 2000 created the Alberta Balancing Pool. The amended legislation provides that the relevant utility is to purchase power at the prices set out in the PPA entered into pursuant to the *Small Power Research and Development Act (Alberta)* (the "**Small Power Act**") and sell the power into the Power Pool. All revenues associated with the sale of such power into the Power Pool are to be paid into the Balancing Pool and all costs associated with such PPAs are to be paid out of the Balancing Pool. The effect of the amendments is to render a utility that is a party to such a PPA a flow through for the rights and obligations under the PPA.

The government of Alberta repealed the EU Act and proclaimed in force a new *Electric Utilities Act (Alberta)* on June 1, 2003 and the *Independent Power and Small Power Regulation* (the "**IPSPR**"). The EU Act effected alterations to the governance of institutional entities such as the Power Pool and the IPSPR addressed payments to be made to and by the Balancing Pool, but neither served to alter the Small Power Act-related arrangements described above.

Ontario

In 1987, the provincial utility and the provincial government developed policies and programs to encourage the addition of new generation by independent power generators. Over 90 of these independent generators or non-utility generators entered into long-term PPAs with Ontario Hydro. These projects represent over 1,225MW of energy from a variety of fuels, such as water, natural gas and wood wastes.

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

The restructuring of Ontario Hydro and the Ontario energy market and the current decisions of the Ontario Government have not had a material impact on the long term PPAs for each generating Facility located in Ontario in which APCo has an interest. The Ontario Electricity Financial Corporation (**"OEFC"**) now holds all rights, obligations and liabilities under such PPAs. This Ontario government agency will continue to purchase the energy generated by the Ontario facilities in which APCo has an interest pursuant to the existing contracts. APCo has also received a licence to generate from the OEB as required by the *Energy Act (Ontario)*.

On March 21, 2006, the Ontario government announced a new program to promote the use of clean, renewable electricity by setting a standard price that made it easier for entrepreneurs and businesses to sell clean power from small projects to the grid. Through Ontario's Standard Offer Program, the government established a fixed price for small renewable energy projects. Under the program, the Ontario Power Authority purchases electricity produced by wind, biomass or small hydroelectric at a base price of 11 cents per kilowatt-hour. The fixed price for solar was be 42 cents per kilowatt-hour (**"kW-hr")**. To date the Province is currently reviewing the program rules.

Discussions with the Ontario Power Authority indicate that energy procurement initiatives will be positively influenced by the *Green Energy Act (Ontario)* introduced by the Ontario government through Bill 150 on February 23, 2009. The *Green Energy Act (Ontario)* is intended to provide the catalyst for the development of 50,000 new green economy jobs and is viewed as positive for the development of renewable energy in Ontario. In anticipation of this, APCo's Development division is maintaining relationships with potential partners for the development of a number of projects that could qualify under anticipated procurement initiatives undertaken by the Ontario Power Authority in accordance with the *Green Energy Act*. In addition, APCo's Development division has applied to become applicant of record for three crown land sites under Ministry of Natural Resources wind power site release program.

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 with the aim of selling off the various components. 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 who 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.

Québec

Between 1991 and 1993, Hydro-Québec negotiated and signed agreements with private producers for the purchase of a total of 474 MW from hydroelectric generating facilities, wind powered facilities and 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 is required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased by APCo within the Province of Québec. APCo's Renewable Energy division anticipates completing the required assessments during the first quarter of 2010. Upon completion of these assessments, APCo is required to submit plans for undertaking any remedial measures that are identified to comply with the legislation. As a result of nine completed and two partially completed assessments underway, APCo has initially identified capital expenditures estimated at approximately $17.5 million. APCo anticipates that these expenditures will be required to be invested over the next five years as follows:

	Total	2009	2010	2011	2012	2013
Estimated Capital Expenditures	**$17,500**	5,000	6,000	1,200	2,800	2,500

The majority of these capital costs are associated with the Donnacona, St. Alban and Mount-Laurier Facilities. APCo does not anticipate any significant impact on power generation or associated revenue while the dam safety work is ongoing. APCo is also exploring several alternatives to mitigate the capital costs of modifications, including cost sharing with other stakeholders and revenue enhancements which can be achieved through the modifications.

On November 2002, the Québec government announced that there would be no new dams built for small hydroelectric projects.

In May 2006, the Québec government unveiled its energy strategy (2006-2012) following a broadly-based consultation process that began in November 2004. The Québec government announced that it would strengthen its energy supply security by giving priority to hydroelectricity, wind energy potential, hydrocarbon reserves and the diversification of natural gas supplies.

New Hampshire

New Hampshire has one large, investor-owned utility, Public Service Company of New Hampshire (the " **PSCNH**"), which is a subsidiary of Northeast Utilities, as well as a number of smaller regional utilities. With the passing of PURPA in 1978, the New Hampshire legislature passed the *Limited*

Electrical Energy Producers Act which directed the NHPUC to encourage the State's utilities to purchase independently produced power from a variety of sources. The State legislature also granted the NHPUC authority to set long term rates for renewable energy sources and beginning in 1984, the PSNH issued PPAs with long term fixed power purchase rates that helped stimulate the development of small hydroelectric generating facilities. While these rates were based on PSNH's own projected energy costs at that time, the contracted rates are now well above today's market rates for electricity. The NHPUC also issued rate orders to utilities such as PSNH to purchase electricity from certain power producers at stipulated power purchase rates.

In March 2002, PSNH approached all the existing holders of PPAs and rate orders with an offer to buy down or buy out the existing contracts that contained over market power purchase rates. By the end of the year, PSNH either bought out or bought down twelve contracts or rate orders.

New York State

Following the implementation of PURPA in 1978, New York State aggressively pursued the development of independent power production. There are currently over 300 independent power facilities now in operation in New York State and independent power producers have added more than 6,000 MW of new electric generating capacity.

(iii) Material Facilities

Long Sault Rapids Facility – Abitibi River, near the Town of Cochrane, Ontario

The Long Sault Rapids Facility is an 18,000 kilowatt hydroelectric generating facility located on the Abitibi River, 19 kilometers north of the Town of Cochrane, in northern Ontario. The Facility was commissioned on April 1, 1998.

The 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 "*Hydroelectric – Long Sault Rapids Facility – Credit Agreements*" below).

The 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.

Power Purchase Agreement

Pursuant to the terms of the PPA, the Co-Owners sell power produced by the 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 the greater of OEFC's Total Market Cost index (a minimum of 1% to a maximum of 8%).

The Co-Owners will not receive a monthly capacity payment unless the Facility delivers an average of at least 1,800 kilowatts of power is 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 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 Facility on their behalf for nominal consideration.

Credit Agreements

There is an outstanding senior loan against the Facility in the amount of $40.6 million at December 31, 2009. 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 December 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 APUC 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, the Fund issued an irrevocable letter of credit in an amount of $1.2 million to replace the debt service escrow deposit. At December 31, 2009, the debt reserve was fully funded using the irrevocable letter of credit.

In addition, APCo owns the LSR Subordinate Note.

Saint-Alban Facility – Ste-Anne River near the Village of Saint-Alban, Québec

The Saint-Alban Facility is an 8,200 kilowatt hydroelectric generating facility located on the Ste-Anne River approximately one kilometer from the Village of Saint-Alban, Québec and approximately 200 kilometers east of Montréal. The Facility consists of a newly gated spillway and the existing dam and spillway, which were rehabilitated and reconditioned in 1996, two penstocks, a powerhouse structure and a tailrace canal and has been designed as a run-of-the-river facility.

Land and Water Rights

The land upon which the Facility is located is currently owned by the Government of Québec. Certain hydraulic rights previously owned by Shawinigan Electric Company, a wholly-owned subsidiary of Hydro-Québec, were acquired during 2006. The Government of Québec entered into a 20 year lease agreement with SNC-Lavalin Inc., a Canadian corporation ("SLI"). The lease agreement will expire in 2016 and will be retroactive to the commissioning date of the facility in 1996.

In addition to contractual lease payments and other amounts payable to the Government of Québec, an annual royalty is payable in respect of the Saint-Alban municipal park.

The Government of Québec has approved the transfer of the leasehold interests from SLI to APFC. Acquisition of legal title to this Facility was not completed in 2009 and is now expected to be completed in 2010, once the leasehold interests are properly registered with the Government of Québec.

Glenford Facility – Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec

The Glenford Facility is a 4,950 kilowatt hydroelectric generating facility located on the Ste-Anne River approximately one kilometer from the Village of Ste-Christine d'Auvergne, Québec and approximately 230 kilometers east of Montréal. The Facility consists of the existing dam and spillway, which were rehabilitated and reconditioned in 1995, an intake, powerhouse and tailrace structure and has been designed as a run-of-the-river facility. The Glenford Facility is owned by the Société en Commandite Chute Ford (the **"Glenford Partnership"**), a limited partnership formed under the laws of Québec comprised of APC and a separate Ontario corporation which is currently wholly-owned by APC and which holds a 0.01% limited partnership interest. APCo indirectly holds the 8.5% secured subordinated note of APC against the Glenford Facility due by July 1, 2023 in the principal amount of approximately $5.0 million issued to APFC on July 7, 1998.

Land and Water Rights

The Glenford Facility has been constructed on certain lands purchased by the Glenford Partnership. The land owned by the Glenford Partnership includes the bed of the river upon which the existing dam structure is located and certain lands on either side of the river. Accordingly, no lease from the Province of Québec is required.

Credit Agreement

There is an outstanding senior loan against the Glenford Partnership in the amount of $4.6 million as at December 31, 2009. The loan was provided by Corpfinance International Limited and has a term of 25 years which commenced in April 1995. The loan is to be repaid in equal monthly payments of $63,591 representing blended interest and principal during its term. The loan is secured solely by the Facility and the ownership interests therein.

A hydrology reserve fund with a balance as at December 31, 2009 of $224,000 has been established to provide additional security in respect of the payment of interest and principal on the Glenford senior debt. Under the terms of the credit agreement, such reserve is required to be increased at the rate of 9% on an annual basis. A maintenance reserve fund with a balance as at December 31, 2009 of $170,000 has been established in respect of major capital expenditures which may be incurred by the Glenford Partnership.

Rawdon Facility – Ouareau River near the Village of Rawdon, Québec

The Rawdon Facility is a 2,500 kilowatt hydroelectric generating facility located on the Ouareau River approximately one kilometer from the Village of Rawdon, Québec and approximately 70 kilometers north of Montréal. The Facility consists of an existing dam (which was rehabilitated and reconditioned in 1986 by Hydro-Québec), intake, spillway, penstock, powerhouse and tailrace structure and has been designed as a run-of-the-river facility. The Rawdon Facility is owned by APFC.

Land and Water Rights

The land upon which the Facility is located and the hydraulic rights necessary for the operation of the Facility are leased from the Ministry of Natural Resources, Québec pursuant to a 20 year lease agreement. The lease expires in June 2014 and includes a renewal option for an additional 20 year period, exercisable by the lessee upon mutually acceptable terms. The lease may be terminated by the Province of Québec upon, among other events, termination of the PPA for the Facility with Hydro-Québec or transfer of the leasehold interest without approval of the landlord.

Saint-Alban, Glenford and Rawdon Power Purchase Agreements

The term of the PPAs for each of the Rawdon Facility and the Saint-Alban Facility, respectively, is 20 years from the commercial start-up date and is 25 years from the commercial start-up date for the Glenford Facility. The PPAs expire in 2014, 2016 and 2020 for the Rawdon, Saint-Alban and Glenford Facilities, respectively. The agreements may be renewed at the option of the generator for a period not exceeding the original term upon mutually acceptable terms. See "*Saint-Alban, Glenford, Rawdon, Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup and Donnacona Power Purchase Agreements – General*" below.

Côte Ste-Catherine Facility – St. Lawrence River near the Town of Ste.-Catherine, Québec

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 11,120 kilowatts. The Côte Ste-Catherine Facility is owned by the Mont-Laurier Partnership.

Land and Water Rights

The land and water rights necessary for the construction and operation of the Côte Ste-Catherine Facility have been obtained from the St. Lawrence Seaway Authority by way of a lease agreement dated Province of Québec has March 1, 1988, as amended. In 2009, the existing water rights lease was renewed for an additional term of 21 years commencing March 1, 2009. Although the Facility is located on a federal waterway, the 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".

Ste-Raphaël Facility – Rivière de Sud, near Québec City, Québec

The Ste-Raphaël Facility is a 3,500 kilowatt hydroelectric generating facility located on the Rivière de Sud approximately 60 kilometers east of Québec City, Québec. The Ste-Raphaël Facility is owned by APFC.

Land and Water Rights

The land and hydraulic rights necessary for the operation of the Facility have been leased from the Ministry of Natural Resources and the Ministry of Environment (Québec) pursuant to a lease agreement dated December 14, 1993. The lease will expire on December 14, 2013 and may be renewed for an additional period of 20 years at the option of the lessee upon terms imposed by the government.

Mont Laurier Facility – Rivière-du-Lièvre near the Town of Mont Laurier, Québec

The Mont Laurier Facility is a 2,725 kilowatt hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec. The Mont Laurier Facility is owned by the Mont-Laurier Partnership.

Land and Water Rights

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.

Rivière-du-Loup Facility – Town of Rivière -du-Loup, Québec

The Rivière-du-Loup Facility is located on the Rivière-du-Loup in close proximity to the downtown section of the Town of Rivière-du-Loup, Québec. The total installed capacity of the Facility is 2,600 kilowatts. The Rivière-du-Loup Facility is owned by APFC.

Land and Water Rights

The land and hydraulic rights necessary for the operation of the Facility have been leased from the Ministry of Natural Resources and the Ministry of the Environment (Québec) pursuant to a lease agreement dated November 20, 1997. The lease terminates on October 22, 2015. The lease can be extended for an additional period of 20 years at the option of the lessee upon terms imposed by the government.

Côte Ste-Catherine, Ste-Raphaël, Mont Laurier and Rivière-du-Loup Power Purchase Agreements

The term of the PPAs for each of the Côte Ste-Catherine (Phase I), Ste-Raphaël, Mont Laurier and Rivière-du-Loup Facilities, respectively, is 20 years from the commercial start-up date and is 25 years from the commercial start-up date for the Côte Ste-Catherine Facility (Phases II and III). For the Côte Ste-Catherine Facility (Phases II and III), the PPAs expire in November 2018 and 2021, respectively. Côte Ste-Catherine (Phase I) PPA was renewed in November 2009 for a term of 11 years expiring on the same date as Phase III in November 2020. The expiry dates for the PPAs for the Ste-Raphaël, Rivière-du-Loup and Mont Laurier facilities are 2014, 2015 and 2027, respectively. The agreements may be renewed at the option of the producer for a period not exceeding the original term upon terms imposed by Hydro-Québec. See "*Saint-Alban, Glenford, Rawdon, Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup and Donnacona Power Purchase Agreements – General*" below.

Donnacona Facility – Jacques Cartier River near the Town of Donnacona, Québec

The Donnacona Facility is a 4,800 kilowatt hydroelectric generating facility located on the lower portion of the Jacques Cartier River, near the Town of Donnacona, Québec. The Jacques Cartier River flows south and empties into the St. Lawrence River approximately 60 kilometers west of Québec City, Québec. The Donnacona Facility is owned by the Donnacona Partnership, of which all of the partnership interests are held directly or indirectly by APFC.

Power Purchase Agreement

The PPA for the Facility has a term of 25 years, expiring in 2022. The agreement may be renewed at the option of the Donnacona Partnership for a period not exceeding the original 25 year term upon terms to be negotiated. Hydro-Québec can veto the renewal, but only if the Donnacona Partnership is in default of a material term of the agreement. See "*Saint-Alban, Glenford, Rawdon, Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup and Donnacona Power Purchase Agreements – General*" below.

Land and Water Rights

The Facility is located on property owned by the Donnacona Partnership. In addition to the land, the existing dam structure, the bed of the Jacques Cartier River upstream of the facility and the natural hydraulic forces of that part of the river are owned by the Donnacona Partnership.

The Donnacona Partnership holds certain easements which allow access to the dam and other structures located near the powerhouse.

The Donnacona Partnership has entered into a lease with the Province of Québec in respect of a section of the bed of the river upstream from the facility and water rights relating to the Jacques Cartier River necessary for the operation of the facility which expires on February 6, 2017. The lease includes a renewal option for an additional 20 year period, exercisable at the request of the Donnacona Partnership upon terms imposed by the Province of Québec.

Rights to all necessary lands have been obtained in order to operate and maintain the transmission line for the facility.

Saint-Alban, Glenford, Rawdon, Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup, and Donnacona Power Purchase Agreements - General

Each of the Saint-Alban, Glenford, Rawdon, Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup and Donnacona Facilities 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.

Tinker Hydro Facility –* Aroostook River *near the town of Perth Andover, New Brunswick

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 one diesel generator; the total nameplate capacity of the station equals 37MW. Hydro Units 1 through 4 (11MW nameplate

capacity) are vertical Francis units and Unit 5 (25MW nameplate capacity) is vertical Kaplan unit. Due to a failure of a connecting rod on turbine blade assembly, Unit 5 has been temporarily converted to a fixed bladed runner. The Facility was originally constructed near the turn of the last century. Units 1, 2, and 3 were installed in the early 1920's, Unit 4 was installed in the 1950's and Unit 5 was installed in 1965. Historical gross generation from the station averages 128,000 MW-hrs per year. Tinker benefits from the flow regulation of the Millinocket dam and the Squa Pan dam Facilities, both of which are also owned and operated by APCo.

Transmission facilities

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 Tinker 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.

Power Purchase Agreements

At present, the Tinker Facility supplies approximately 31,500 MW-hrs per year to the municipal utility of Perth-Andover under a power purchase and sale agreement. The remaining generation from the plant, approximately 100,000 MW-hrs per year, is sold to AES, which provides energy 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.

Dickson Dam Facility – Town of Innisfail, Alberta

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

Power Purchase Agreement

The Dickson Dam PPA was entered into with TransAlta Utilities Corporation (" **TransAlta**") on December 7, 1990 and was approved by the Alberta Public Utilities Board on January 16, 1991. It has a term of 20 years ending on January 16, 2012. Under this agreement, TransAlta is obligated to accept delivery of all electricity in amounts up to 115% of the 12.7 MW capacity which is allocated to the Facility at rates stipulated by the Small Power Act.

Use of Works Agreement

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 waterflows 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.

Phoenix Facility – Oswego River near the Town of Phoenix, New York

The Phoenix Facility is located on the Oswego River, in the Town of Phoenix, Onondaga County, New York. The Facility is located at an 866 foot long concrete ogee spillway which is owned by New York State Thruway/Canal Corporation (the "**NYSTA/CC**"). It is a run-of-the-river facility and is rated at 3,500 kilowatts. The Facility has two single regulated turbines. This Facility is owned by Oswego Hydro Partners L.P., which is indirectly owned by APCo.

Power Purchase Agreement

The original agreement was dated September 19, 1989, with a term commencing March 28, 1986. The agreement requires maintenance of an adjustment account based on the difference between the specified rate and 90% of the long run Avoided Costs.

Land and Water Rights

Oswego Hydro Partners L.P. holds certain permanent easements on land and buildings used by the Facility. The Phoenix Facility is located at the Oswego Canal Lock No. 1 on the Oswego River. The dam, reservoir and navigation lock are owned by the State of New York and are operated and maintained by the NYSTA/CC.

(b) 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 wind St. Leon Facility currently is Manitoba. The electricity generated by the wind turbines at the St. Leon Facility is transmitted via underground distribution lines to the Facility's substation for subsequent delivery to the transmission system of the purchaser, Manitoba Hydro-Electric Board ("**Manitoba Hydro**"). The purchaser then distributes the electricity to its customers or to other endpoints via the grid.

Manitoba

Prior to Manitoba Hydro negotiating the PPA with St. Leon LP and St. Leon GP in respect of the St. Leon Facility, Manitoba did not have independent wind power generation facilities in service. In the past, 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.

In 2002, the Manitoba government developed a strategy on climate change to meet or exceed targets established under the Kyoto Protocol to the United Nations Framework Convention on Climate Change. The Manitoba strategy is based on recommendations from the Climate Change Task Force through the Climate Change Action Plan. The plan supports numerous clean energy programs within the provincial government and municipalities as well as within business, outside agencies, academic institutions and the public.

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, Manitoba Hydro has advised it plans to have approximately 1,000 MW of wind power capacity (inclusive of the generating capacity represented by the St. Leon Facility), to be constructed, using in part, independent power producers by 2010. It is anticipated another provincial proposal will be released in 2010 and APCo's Development division believes the Glenwood and St. Leon expansion proposals will be examined by the Province of Manitoba as options for achieving its wind power generation targets.

(iii) Material Facilities

St. Leon Facility – St. Leon, Manitoba

The St. Leon Facility is a 99 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg. The Facility owned by St. Leon LP.

On September 18, 2007, the turnkey construction contractor and wind turbine manufacturer, Vestas, achieved commercial operation of the Facility pursuant to the Vestas Contract. The commercial operation date marked the commencement of a five year warranty period with Vestas. The parties have recently agreed to execute an Operation and Maintenance Service Agreement whereby Vestas shall provide operation, maintenance and repair services to the St. Leon Facility for approximately 20 years.

Power Purchase Agreement

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 $1.7 million is required. In 2008, APCo reached an agreement with Manitoba Hydro to replace the cash security with an irrevocable letter of credit. As at December 31, 2009, the security was fully funded using an irrevocable letter of credit.

St. Leon LP entered into a 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.

Credit Facility

A banking syndicate provided a senior loan to the St. Leon Trust in the amount of $70.5 million as at December 31, 2009 to finance construction of the St. Leon Facility. The loan has a term of 5 years and matures in October 2011. The senior loan bears interest at banker's acceptance rate plus a banking charge of 1%, payable monthly. St. Leon Trust has entered into an interest rate swap arrangement to fix the interest on the loan at 4.47%. The loan is secured solely by the Facility and the ownership interests therein.

(c) 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. To reduce the total tonnage of municipal waste being directed to landfills and to extend the useful life of existing landfills, considerable effort is being directed toward the establishment of energy from waste (**"EFW"**) facilities. The establishment of EFW facilities is now a licenced process in certain states of the United States and Canadian provinces.

Both thermal energy in the form of steam and electrical energy are produced from incinerating the waste. The heat is used to make steam and to drive turbines and generate electricity.

(ii) Principal Markets and Distribution Methods

See *"Material Facilities"*, below.

(iii) Material Facilities

EFW Facility – Brampton, Ontario

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 to produce an average of approximately 60,000 pounds per hour of steam which is the excess of the steam required for production of internally consumed electricity. It is owned by APEFW which is wholly-owned by KMS.

The EFW Facility experienced an unplanned outage in January 2010 related to problems with boiler tubes. The Facility is expected to be operational in spring 2010 once the boiler tube issues are resolved. APCo is accelerating capital maintenance originally planned for the second and third quarters of 2010 during this outage which should allow the facility to make up some of the income expected to be lost in the first quarter in the remainder of 2010.

The EFW Facility produces steam from the incineration process. The steam was previously run through a steam turbine to generate electricity, a portion of which was used by the EFW Facility and the remainder was then sold to OEFC. In June 2008, the BCI Facility was commissioned and operational. See "*BCI Facility – Brampton, Ontario*" under "*Material Facilities*" for Cogeneration. As a result, the majority of the existing steam produced by the Facility is now diverted to the BCI Facility.

Power Purchase Agreement

The EFW Facility has entered into a PPA with OEFC which requires OEFC to purchase all the electricity produced by the Facility. The OEFC uses the electricity to supply the grid in Ontario. The PPA expires in 2012.

Fuel Supply

Under a “tip or pay” waste supply agreement with the Regional Municipality of Peel (“ **Peel**”), Peel supplies the Facility with a minimum of 127,900 tonnes per year of acceptable municipal solid waste. The agreement expires in 2012. Peel has the option to renew the agreement for an additional five-year term. The agreement requires Peel to pay a “tipping fee” for each tonne of acceptable waste delivered, plus an additional fee for each tonne of acceptable waste delivered above the base amount. Additional volumes of waste may be supplied by Peel at the request of either party, subject to the agreement of the other. The agreement provides that if certain taxes are imposed or revised standards are set for certain environmental or operating matters affecting the Facility, the tipping fees paid by Peel will be increased to reflect the increased capital or operating costs so imposed by the taxes or revised standards.

(d) 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 Thermal Energy division’s cogeneration facilities are California and Connecticut. The electricity produced from these Facilities is conveyed from the relevant facility to the load serving entities for electricity markets mostly pursuant to the terms of long-term contracts. In addition, capacity is sold to the purchaser under these long-term contracts. A summary of the contracts for the Cogeneration Facilities is attached in Schedule B. The thermal energy is also sold to nearby third party purchasers for use in their production facilities.

California

The California Legislature passed Assembly Bill 1890 in 1996 to restructure the electricity industry. The State restructuring law dramatically changed the market system that was in place for more than eighty years. The intent of the restructuring was to ensure a transition to a more competitive

electricity market by creating a new market that provided competitive low-cost and reliable electric service. While municipal utilities were not required to participate in the restructured market, customers of investor-owned electric utilities were free to choose their electricity provider. The market was controlled by the Power Exchange, which was to provide market services and control, and the Independent System Operator, which was given control over the transmission grid.

The restructured electricity industry took form in early 1998 and the new market appeared to be off to a good start. Initially, as expected, electricity prices tracked closely the marginal cost of power production. Ultimately, however, many implementation problems developed, which eventually elevated to an "energy crisis" in 2000. Problems that began to appear were extremely high costs of electricity, decreased reliability, very high profits by generators and large debts incurred by utilities.

Customers of the investor-owned utilities had their rates frozen as part of the overall legislative design and did not see the high wholesale costs reflected in their utility bills. Because of the rate freeze, utilities could not pass these expenses on to their customers, leaving utilities, such as Pacific Gas and Electric Company ("**PG&E**"), with negative balances in their revenue accounts. PG&E ultimately declared bankruptcy on April 6, 2001.

The California Legislature addressed the crisis by implementing a number of changes to restructure the electricity market. A key component of the changes was to ensure that there was and is an adequate supply of electricity to meet market demands. In September 2002, PG&E filed a Plan of Reorganization which the company stated would allow it to emerge from Chapter 11 protection. On June 19, 2003, federal bankruptcy court announced the settlement agreement between PG&E and the California Public Utility Commission's staff. In December 2003, the California Public Utility Commission approved the settlement agreement and the bankruptcy court confirmed the Plan of Reorganization.

Connecticut

CL&P is part of the North East Utilities System which is located in the New England Power Pool. 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. Six electricity products are bought and sold by market participants on an internet-based market system.

(iii) Material Facilities

Sanger Facility – Sanger, California

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 44MW General Electric LM6000 natural gas fired turbine, commissioned in 2008, and a 12.5MW Westinghouse steam turbine, commissioned in 1991. The Facility is owned by Sanger, LLC, a subsidiary of APFA.

Power Purchase Agreement

Output of the Facility is governed by the terms and conditions of a firm capacity and energy PPA with PG&E. The agreement has a term of 30 years, expiring in 2022, and calls for delivery of 38MW of firm capacity.

An additional 6 MW can be exported with the existing 69 kilovolt (**"kV"**) substation while an upgrade of the existing line voltage by PG&E to 115 kV is required to access the full 14 MW potential. Once PG&E upgrades the existing line voltage to 115 kV, Sanger LLC will install a new substation with additional investment of approximately US $2.0 million. PG&E's upgrade is anticipated to be completed in or after fiscal 2010. The Sanger Facility is expecting to reach agreement on the sale of an additional 6 MW of power beginning in the second half of 2010.

Fuel Supply

Natural gas for the 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.

Energy Lease

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 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.

Credit Facility

There is an outstanding senior loan against the Facility in the amount of US $19.2 million as at December 31, 2008. 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 2009 was 1.44%. The loan is secured solely by the Facility, the ownership interests therein and an irrevocable letter of credit in an amount of US $19.4 million.

Windsor Locks Facility – Windsor Locks, Connecticut

The Windsor Locks Facility is a 56MW (gross) natural gas-fired generating facility located in Windsor Locks, Connecticut. The Windsor Locks Facility is a combined cycle generating station comprised of a 40MW General Electric natural gas fired turbine and a 16MW General Electric steam turbine and was commissioned in 1990. The Facility is owned by Algonquin Windsor Locks LLC, an indirect subsidiary of APCo.

APCo is continuing the preliminary engineering and environmental permitting work for the installation of a new combustion gas turbine more appropriately sized to meet the electrical and steam requirements of Ahlstrom. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to US $450/KW to a maximum of US $6.6 million to offset the cost of

such re-powering. In addition to installing the new gas turbine, APCo would expect to continue to operate and maintain the existing equipment. Any investment in new capital for this site will be based on an assessment of the incremental earnings against such additional investment.

Energy Services Agreement and Ground Lease

The Windsor Locks Facility supplies thermal steam energy and a portion of electrical generation to Ahlstrom Windsor Locks, LLC ("**Ahlstrom**"), a leading paper and non woven materials manufacturer, pursuant to a ground lease and an energy services agreement. Pursuant to the agreement, Ahlstrom leases to the facility site to Algonquin Windsor Locks, LLC and utilizes thermal steam energy and a portion of electrical generation of the Windsor Locks Facility for use at its specialty fibers composites mill located adjacent to the Windsor Locks Facility. Both the ground lease and the energy services agreement expire in January 2018, subject to certain early termination rights in favour of Ahlstrom and rights of renewal in favour of both parties. Payments under the energy services agreement are fully indexed to the cost of natural gas consumed by the Facility.

Power Purchase Agreement

The remainder of the electrical output of the Windsor Locks Facility is governed by the terms and conditions of a PPA with CL&P. The agreement expires in April 2010.

Commencing in April 2010, APCo will maximize net revenue by serving the steam and power requirements of Ahlstrom pursuant to the ESA together with bidding the remaining available capacity of approximately 40 MW into the thirty minute forward operating reserve market ("**TMOR**"). APCo has entered into an agreement with Emera Energy Services Inc. to manage the off-take sales from this Facility into the ISO NE market. See "*Current Development Projects - Windsor Locks*" under "*Development*" for further details.

Fuel Supply

Natural gas for the Facility is delivered under a gas supply agreement with Yankee Gas Service Company (" **Yankee Gas**"). Gas is supplied by Yankee Gas at a percentage of its weighted average cost of gas for the month. The gas contract contains minimum annual consumption requirements with associated penalties for shortfalls. The Yankee gas agreement is also schedule to terminate coincident with the PPA and a new agreement is being drafted which will allow Windsor Locks to use Yankee Gas as a local distribution company which will enhance Windsor Lock's purchase options for its natural gas requirements.

BCI Facility – Brampton, Ontario

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 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.

Kirkland Facility – Kirkland Lake, Ontario

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 Facility is sold to OEFC pursuant to a 40 year contract, which expires in 2030. Natural gas used by the Kirkland 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. Kirkland has a put option to sell the Kirkland Facility to Northland with an exercise date of February 28, 2011 at an exercise price of $10 million. Further to a shareholder meeting on November 12, 2009, the Kirkland shareholders decided not to exercise the put option as the present value of the expected future dividends from this investment were expected to exceed funds they would receive from the put option. As a result, subsequent to February 28, 2011, 75% of operating income of the Facility will be paid to Northland under the management agreement.

Cochrane Facility – Town of Cochrane, Ontario

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 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. Cochrane has a put option to sell the Cochrane Facility to Northland with an exercise date of February 28, 2011 at an exercise price of $3 million. Further to a shareholder meeting on November 12, 2009, the Cochrane shareholders decided not to exercise the put option as the present value of the expected future dividends from this investment were expected to exceed funds they would receive from the put option. As a result, subsequent to February 28, 2011, 75% of operating income of the Facility will be paid to Northland under the management agreement.

(e) Power Generation - Development

(i) Target Markets / Development Strategy

The Development division works to identify, develop and construct new, renewable and efficient energy generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APCo's existing facilities. Development is focused on projects within North

America with a commitment to working proactively with all stakeholders, including local communities. The Development division is led by five full time employees who have access to, and support from, all of APCo's available resources to assist it in the development of projects. Typically, the division draws upon the support of the finance, engineering, technical services, and environmental and regulatory compliance groups. It also utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains expertise, as required, from the financial, legal, engineering, technical, and construction sectors.

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

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

(ii) Principal Market Environment

APCo 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. More recently, the Ontario government has introduced the *Green Energy Act*. This legislation is the primary procurement mechanism for renewable and clean energy and obliges the responsible power authority to purchase power at a stipulated tariff from green energy projects. It also requires all utilities to grant priority grid access to such projects. The intention of the proposed legislation is to make development of renewable energy projects significantly easier than the prior process of formal bids in response to requests for proposals from the responsible power authority

The North American renewable energy market is experiencing substantial growth. It is being supported by increases in the demand for greater installed capacity of renewable energy projects. Canada has seen average annual growth of over 30% for the last 5 years in the wind energy industry, with a current installed capacity of 3,426 MW. Industry observers expect that renewable energy generated from wind will grow to 12,000 MW by 2016. This expectation is supported by various provincial objectives including: Ontario - 4,600 MW by 2020; Québec - 4,500 MW by 2016, Alberta - 2,500 MW in additional transmission options, Manitoba - 1,000 by 2017 and the Maritime Provinces - 800 MW by 2015, as well as anticipated initiatives in Saskatchewan. By the end of September 2008, the U.S. wind industry had an installed capacity of over 21,000 MW, compared to 10,000 MW as at December 2006.

APCo continues to actively pursue development projects which provide the opportunity to exhibit accretive growth. APCo anticipates its involvement in many future opportunities as initiatives designed to support independent power producers are being extensively supported by Canadian provincial governments and a significant number of U.S. states.

In the United States, the *New Energy for America Plan* supports 10% of the country's electricity being generated from renewable sources by 2012 and 25% by 2025. The demand for additional renewable power is also expected to benefit from the desire by various government entities to increase infrastructure spending.

(iii) Current Development Projects

Red Lily

APCo continues to advance the Red Lily Wind Project in south-eastern Saskatchewan (the " **Project**" or "**Red Lily**"). In July 2008, a 25 MW PPA for the first phase of the Project ("**Phase I**") was executed with SaskPower after Phase I was successfully bid into a SaskPower Environmentally Preferred Power Strategy Request for Proposal. In June 2009, APCo and Natural Resources Canada ("**NRC**") executed a Contribution Agreement under the ecoENERGY for Renewable Power Program for Phase I, securing funding for the project in advance of the expectation of the program being fully subscribed later in 2009. APCo has submitted to NRC the Environmental Impact Assessment documentation for review in relation to obtaining funding under the federal ecoENERGY program and is following up with NRC, as the lead agency, on comments received from other agencies. Notably, on April 13, 2009 Saskatchewan Environmental Assessment Branch confirmed that APCo had satisfied the requirements under the Provincial Environmental Assessment Act for Phase I.

APCo is considering a number of financing alternatives for Red Lily. Currently, the most likely alternative will see the Project financed through an equity injection from a third party together with APCo's participation arising in the Project solely through a subordinated debt commitment of up to $19.0 million. APCo would retain responsibility and receive fees in respect of the development, construction, operation and supervision of the Project. After 5 years, APCo would have an option to subscribe for a 75% equity interest in the Project in exchange for its subordinated debt commitment.

On behalf of Red Lily, APCo is in the process of finalizing the contracts necessary to construct the project and has executed term sheets to secure all of the required financing, with the anticipation that the funding will be available in the early part of the second quarter of 2010. The earliest expected commissioning date of the project is December 31, 2010. In addition to the focused effort on Phase I, APCo has secured additional property and is assessing the viability of an expanded project. The viability of the expanded project will be conditional upon actual operating results from Phase I.

Successful development of wind projects such as Red Lily are subject to significant risks and uncertainties including the ability to obtain financing on acceptable terms within deadlines imposed by the utility, reaching agreement with any other external parties involved in the project, currency fluctuations affecting the cost of major capital components such as wind turbines, price escalation for construction labour and other construction inputs and construction risk that the project is built without mechanical defects and is completed on time and within budget estimates. Assuming the Project is developed, it is currently estimated to require 16 turbines with a capital investment of approximately $65 million. Annual energy production from the wind farm is estimated to be 88,100 MW-hrs and annual gross revenue is estimated to be $8.5 million.

Windsor Locks

The Windsor Locks Facility was acquired in 2003 and currently has an outstanding net book value to APCo of approximately US$17.2 million as at December 31, 2009. The Facility has two key energy agreements. The first agreement is the PPA with CL&P which expires in April 2010. The second agreement is the Energy Services Agreement ("**ESA**") with Ahlstrom, which, if not further extended by mutual agreement, will continue until 2017. The expiration of the CL&P PPA will impact operations beyond April 2010.

Commencing in April 2010, APCo will maximize net revenue by serving the steam and power requirements of Ahlstrom pursuant to the ESA together with bidding a portion of the remaining available capacity of approximately 40 MW into the thirty minute forward operating reserve market ("**TMOR**"). APCo has entered into an agreement with Emera Energy Services Inc. to manage the off-take sales from this facility into the ISO NE market.

The Development division currently anticipates operating cash flow at the Windsor Locks facility for 2010 to be approximately U.S. $4.5 million compared to a historical cash flow of approximately U.S. $8.0 million. This operating cash flow estimate assumes successful participation in the summer 2010 and the winter 2010/2011 forward reserve auctions. TMOR has cleared at US $14 per MW month for the last 7 forward reserve procurement periods (two periods annually). During 2010, it is expected that APCo will earn revenue from steam and electrical sales to Ahlstrom, steam and electrical capacity payments made by Ahlstrom, energy sales to ISO-NE, capacity payments made by ISO-NE and TMOR payments made by ISO-NE. Under this operating protocol APCo will need to acquire 750,000MMBTU to 835,000MMBTU of natural gas annually in addition to the natural gas purchases reimbursed by Ahlstrom.

APCo is continuing the preliminary engineering and environmental permitting work for the installation of a new combustion gas turbine more appropriately sized to meet the electrical and steam requirements of Ahlstrom. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to US $450/KW to a maximum of US $6.6 million to offset the cost of such re-powering. In addition to installing the new gas turbine, APCo would expect to continue to operate and maintain the existing equipment. Any investment in new capital for this site will be based on an assessment of the incremental earnings against such additional investment.

Other

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

(iv) Future Development Projects – Greenfield Projects

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

In addition to the second phase of the Red Lily project, APCo is currently collecting wind data on three other sites in Saskatchewan and expects to respond to the Provinces' Request for Qualifications to procure up to 175MW of wind power from one or more independent power producers.

APCo owns the rights, including land options, meteorological towers and historical wind data related to a potential 80MW Ontario-based wind project. In the event the project is developed, it is currently estimated to require an investment of up to $250 million and is expected to require 2 to 3 years to complete.

In 2008, APCo made a strategic decision to maintain land option agreements for two wind projects in Quebec in anticipation of future provincial tenders. In May 2009, Hydro Quebec released details in relation to a tender request for wind projects of a 25MW maximum size. In addition, APCo has developed a relationship with two development co-operatives comprised of landowners and other small investors for the potential development of a third and fourth project in response to the expected call for tender. APCo will assess the economics of these projects individually and will bid into the RFP accordingly.

Discussions with the Ontario Power Authority indicate that energy procurement initiatives will be positively influenced by the Green Energy Act ("**GEA**") which received Royal Assent on May 14, 2009. The GEA is intended to provide the catalyst for the development of 50,000 new green economy jobs and is viewed by APCo as positive for the development of renewable energy in Ontario. The Development division is maintaining relationships with potential partners for the development of a number of projects that could qualify under anticipated procurement initiatives undertaken by the Ontario Power Authority in accordance with the GEA. In addition, APCo has applied to become applicant of record for three crown land sites under the Ministry of Natural Resources wind power site release programme, and has recently submitted 42MW of on-shore wind energy projects in eastern Ontario under the GEA's Feed-in Tariff program ("**FIT**"). The on-shore wind price set by the FIT program is $0.135 per kWH.

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

(v) Future Development Projects – Existing Facilities

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

Renewable Energy

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

Thermal Energy

The EFW Facility is designed to incinerate over 500 tonnes per day of municipal solid waste from Peel to produce steam that is used in the production of electricity and to supply the internal steam load for a nearby recycled paper board manufacturing mill. APCo established BCI to operate the required facilities to supply steam to the nearby paper board customer and pursue additional steam load customers.

The Development division is currently reviewing several proposals at the EFW Facility to expand its power generation and waste processing throughput capacity. Throughput capacity could be expanded by between 40,000 and 100,000 tonnes annually depending on the proposal that is selected. If the expansion is pursued, depending on the alternative chosen, an investment of between $60 million to $250

million would be required. APCo is currently evaluating the feasibility of an expanded facility including associated capital and operating costs and financing terms. APCo is also engaged in discussions with Peel to establish a new long term contract for a reliable supply of municipal solid waste.

(f) Water and Wastewater Utility Services

(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 potable water is delivered to the customer through the distribution system, at pressures generally ranging from above 20 pounds per square inch (psi) to 100 psi, through a utility owned meter typically placed at the lot line, and into a service line which is owned and maintained by the customer.

These distribution pipes are constructed of materials ranging from plastic (PVC, HDPE) to metals (ductile iron, steel) and occasionally reinforced concrete depending on when they were installed and the surrounding soil conditions. Pipes are placed below the ground surface at depths varying from several feet up to 10 feet, depending upon the frost penetration risk or surface loading factors.

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 production and distribution methods are as follows. 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 buried collection pipes or lines (collection mains) located under or adjacent to the street which pipes are owned and maintained by the private utility. The collection lines (referred to as “mains”) range in size from a minimum of 4 inches in diameter (if in a lightly populated roadway) up to 36 inches in diameter if serving as a trunk line consolidating numerous feeds. These wastewater mains are typically constructed either of plastic where diameters are 16 inches or less and of concrete for larger diameters. These pipes generally slope at a grade of approximately 1% 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.

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.

Fees to customers for wastewater treatment consist primarily of a fixed monthly charge based on customer class determined by connection pipe size. For larger commercial customers, fees may be based on measurement of volumes by means of the water meter. At some utilities, a variable charge may also be applied based on potable water volumes used at the location which volumes are determined by water meter readings. Where the utility provides only wastewater services, the utility may have to rely on the information provided by the local water utility to calculate the variable portion of the rate.

These utility operating companies are regulated investor-owned utilities 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 operate under cost-of-service regulation as administered by these state authorities. The utilities generally 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. In all its markets, APUC monitors the rates of return on each of its 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 Utility Services business unit is attached in Schedule C.

(ii) Principal Markets

The principal markets of Liberty Water are located in Arizona, Texas and Missouri.

Arizona

While water and wastewater services are supplied primarily by large municipalities to their residents, there are still 286 investor-owned water distribution utilities and 46 investor-owned wastewater treatment utilities in Arizona. The Arizona Corporation Commission (the “**ACC**”) is the primary regulatory agency with jurisdiction over economic and services delivery aspects of these water and wastewater treatment utilities as well as all other types of investor-owned utilities. Municipal water and wastewater systems and water improvement districts are not regulated by the ACC but are kept accountable through the electoral process and governance of State and County agencies.

The Arizona Department of Environmental Quality (“ **ADEQ**”) in conjunction with various County agencies (county health units) have primary jurisdiction respecting environmental regulation and compliance.

Missouri

The Missouri Public Service Commission currently regulates 57 water and 5 wastewater investor-owned utilities. Water quality issues are regulated by the Missouri Department of Natural Resources.

Texas

The Texas Commission on Environmental Quality (the “**Texas Commission**”) provides regulatory oversight of investor-owned water and wastewater treatment utilities, including the establishment and revision of rates charged to customers. The Texas Commission 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.

(iii) Material Facilities

Black Mountain Facility – Carefree, Arizona

The Black Mountain Facility is a wastewater treatment facility established in 1971 to support the development of the Boulders Resort and golf course and the surrounding residential development. This utility system is located ten miles north of Scottsdale, Arizona, in the town of Carefree, Arizona. The Facility currently serves approximately 2,100 customers in and around the Town of Carefree and City of Scottsdale. The Black Mountain Facility is owned by a wholly-owned subsidiary of Liberty Water.

The existing wastewater treatment plant is located in the residential section of the Boulders Resort Community, in the immediate vicinity of residences and the Boulders golf course. The plant owned by the utility is permitted to treat 120,000 gallons per day (“**gpd**”) and presently runs at capacity. The effluent produced by the plant is delivered by pipe to an ornamental lake on the Boulders golf course and subsequently used for irrigation. The Facility is an activated sludge plant and produces an effluent which meets or exceeds quality standards for A+ effluent discharge and reuse and which is used for irrigation of the Boulders golf course and surrounding vegetation. Excess wastewater above 120,000 gpd is delivered by pipe to the City of Scottsdale Wastewater Treatment Plant under a bulk services agreement for treatment at their facility.

Gold Canyon Facility – Gold Canyon, Arizona

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 Facility currently serves over 6,500 residential and commercial customers. The Gold Canyon Facility is owned by a wholly-owned subsidiary of Liberty Water.

The treatment plant utilizes an extended aeration process combined with a sequencing batch reactor. Expansion of the treatment plant from a capacity of 1.0 million gpd to 1.9 million gpd, was completed in October 2005.

The Facility is a consumptive re-use facility and sells its reclaimed A+ effluent for use as irrigation water on four 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.

Bella Vista Facility – Sierra Vista, Arizona

The Bella Vista Facility is a water distribution facility formed in 1952 to serve a new motel and several small commercial buildings developed in the Town of Sierra Vista, Arizona. The Facility currently serves approximately 8,200 connected water customers and has experienced a long term growth at the average rate of 3% per year. The Bella Vista Facility is owned by a wholly-owned subsidiary of Liberty Water.

This Facility sources all its raw water from groundwater. There are approximately 29 wells supplying the Bella Vista Facility. This water is disinfected at the source prior to its introduction into the distribution system.

The Facility currently has outstanding indebtedness to the Water Infrastructure Finance Authority evidenced by two 25 year fully amortizing notes. The first note, issued in 1995, bears interest at the rate of 6.10% and has a remaining balance as at December 31, 2009 of US$0.1 million. The other note bears interest at the rate of 6.26% and has an outstanding balance of US$1.5 million as at December 31, 2009.

The Facility operates under a Certificate of Convenience and Necessity and is regulated by the ACC.

Litchfield Park Facility – West Valley of Maricopa County, Arizona

The Litchfield Park Facility is a water distribution and wastewater treatment facility located in the West Valley of Maricopa County, 15 miles west of Phoenix, Arizona whose service area includes sections of the cities of Goodyear, Avondale and all of Litchfield Park, Arizona. The Litchfield Park Facility is owned by a wholly-owned subsidiary of Liberty Water.

The Litchfield Park Facility presently serves approximately 15,200 water and 16,200 wastewater customers. The wastewater facility has permitted capacity of 4.1 million gpd. During 2009, the Facility experienced a 2% growth rate in the number of water and wastewater customers. The 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 customer base through a single pressure zone. In 2007, in response to high growth in connections, the Facility began preparing design plans for expansion of its wastewater treatment facility. However, slowed growth has now postponed such plans and construction related to an expansion of capacity is now anticipated to begin in 2011 or 2012, depending on local demand growth occurring. The Facility now operates at 80% capacity. The Facility supplies Class "A+" effluent to a number of local golf courses in the area.

Credit Facility

The Litchfield Park Facility currently has outstanding indebtedness to the City of Goodyear in the amount of US$11.2 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, 2009 of US $4.0 million bearing interest at the rate of 5.87%. The second series was issued in 2001 with a principal amount as of December 31, 2009 of US $7.2 million and bearing interest at the

rate of 6.71%. 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, 2009 was US$1.2 million.

Fox River Facility – LaSalle County, Illinois

The Fox River Facility is a water distribution and wastewater treatment facility located in LaSalle County, approximately 50 miles south-west of Chicago, Illinois, just outside the town of Sheridan, on the banks of the Fox River. The Facility primarily serves the Fox River Resort, a drive to destination interval ownership operation consisting of approximately 220 equivalent water distribution and wastewater connections.

The Facility is owned by a wholly-owned subsidiary of Liberty Water Co. Currently, only half of the available acreage in the area is developed and the water storage and wastewater treatment plant can accommodate a significant increase in demand without the need for major capital expenditure.

Tall Timbers Facility – Tyler, Texas

The Tall Timbers Facility is a wastewater treatment facility formed in 1983 to serve subdivision developments in the City of Tyler, Texas approximately 90 miles east of Dallas. The Facility now serves approximately 1,260 connected customers consisting of approximately 30 commercial/light industrial connections and the balance representing residential connections. The Facility experienced growth of approximately 5% in 2008. The Facility is owned by a wholly-owned subsidiary of Liberty Water.

The Tall Timbers Facility has a capacity of 445,000 gpd. The Tall Timbers Facility operates under a Certificate of Convenience and Necessity and is regulated by the Texas Commission on Environmental Quality.

Rio Rico Facility – Rio Rico, Arizona

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 Facility serves approximately 6,200 water and 2,100 wastewater connections in the community of Rio Rico, Arizona. The Facility is owned by a wholly-owned subsidiary of Liberty Water.

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

Black Mountain, Litchfield Park, Rio Rico, Bella Vista, Tall Timbers, Woodmark Rate Cases - General

Liberty Water is proceeding through the regulatory process with rate cases relating to a number of its facilities. The Black Mountain facility filed a rate case in December 2008 using a June 30, 2008 test year. The LPSCo facility filed a rate case in March 2009 using a September 2008 test year. The Rio Rico facility filed a rate case in May 2009, using a test year ended December 31, 2008. The Bella Vista, Northern Sunrise and Southern Sunrise facilities filed rate cases in August 2009 using a March 31, 2009 test year. All of these facilities are located in Arizona. Five Texas facilities filed rate cases in April 2009, and Woodmark in Texas filed in July 2009, all with test years ended December 31, 2008.

The following table sets out some particulars with respect to the status of the rate cases as at February 15, 2010:

Facility	Test Year Ending	Status of Rate Case Application	Estimated Annual U.S. $ Revenue Increase as Filed	Estimated Timing of Rate Increase
Arizona				
Black Mountain	**Q2 2008**	Hearing has concluded. Awaiting Recommended Order & Opinion	$ 0.9 million	**Q2 2010**
LPSCo	**Q3 2008**	Hearing has concluded. Awaiting Recommended Order & Opinion	$ 12.5 million	**Q2/Q3 2010**
Rio Rico	**Q4 2008**	Hearing has concluded. Awaiting Recommended Order & Opinion	$ 2.0 million	**Q3 2010**
Bella Vista, Northern and Southern Sunrise	**Q1 2009**	Responding to interrogatories, hearing scheduled for June 28 – July 1, 2010	$ 1.5 million	**Q4 2010**
Texas				
Texas Utilities (Silverleaf – 4 utilities)	**Q4 2008**	Awaiting administrative hearing date	$ 1.2 million	**Interim rates implemented October 2009**
Tall Timbers	**Q4 2008**	Discovery period	$ 0.2 million	**Interim rates implemented July 2009**
Woodmark	**Q4 2008**	Public consultation period	$ 0.1 million	**Interim rates implemented January2010**

Rate cases ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Water monitors current and anticipated operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments.

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

In July 2009, Tall Timbers implemented interim rates to customers in a portion of its service area as applied for in its rate case application. The interim rates are being contested by various homeowner associations in Tall Timbers service area affected by the increase. These rates are expected to be finalized before the end of 2010 as part of the normal regulatory process administered by the Texas Commission.

In October 2009, the Texas Silverleaf utility began charging interim rates based on its rate case applications. The interim rates are being contested by greater than 10% of the customers in the service area. These rates are expected to be finalized before the end of 2010 as part of the normal regulatory process administered by the Texas Commission.

In Arizona, ACC requires a full regulatory process for all rate cases using a historic test year. It is anticipated that the regulatory review of the proposed rates and tariffs for the Arizona facilities would be completed by mid-2010, with the new rates and tariffs in Arizona going into effect throughout 2010.

An exact determination of increased revenues from all rate case applications is not possible at this time as the timing of conclusion to the rate cases and the final decision on rate increases are determined by the regulator. As a result of delays in the progress of rate cases through the regulatory processes, Liberty Water now anticipates that approximately $7 million of additional revenue from rate cases will be achieved in 2010 but the full annualized increase in revenues determined through the rate case processes is expected to be achieved in 2011.

(g) Power Generation - Energy Marketing Business

(i) Production Method

The energy marketing business involves standard offer contracts for the supply of energy to commercial and industrial customers in northern Maine. The energy marketing business is based on a series of short-term energy supply agreements. These include energy sales to customers and utilities for energy supply and energy procurement contracts in northern Maine and the ISO-NE market.

(ii) Principal Markets and Distribution Methods

The Energy Services Business provides energy to commercial and industrial customers in the northern Maine and New Brunswick markets. The Energy Services Business anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 150,000 MW-hrs of energy to its customers at an average rate of $80/MW-hr on an annualized basis. Based on historical long term average levels of hydroelectric energy generation, the Tinker Assets are anticipated to provide greater than 80% of the energy required by the Energy Services Business to service its customers which provide a natural hedge on supply costs of the Energy Services Business.

In addition to the energy generation provided by the Tinker Assets, the Energy Services Business anticipates buying additional energy on the open market in order to services its customer demand. APCo manages the risk associated with this business through internally generated energy from the Tinker Assets, as well as, through the purchase of fixed volume/prices from the ISO NE market. In addition, APCO 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.

(iii) Material Facilities

The Energy Services Business is based on a series of short-term energy supply agreements which generally will expire within the next 14 months. 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.

The hydroelectric and thermal generation assets offer capacity to support the energy services obligations in northern Maine. The acquisition improves hydrologic diversification through a new geographical area to the APCo generation portfolio and builds APCo's Eastern Canadian generating presence.

It is anticipated that the majority of the energy sold by the Energy Services Business will be supplied through generation from the Tinker Assets, based on historical long term average levels of hydroelectric energy generation of these facilities. The Energy Services Business 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.

(h) Thermal - Biomass

(i) Production Method

Biomass is a combustion process that converts organic material into electricity through combustion. The combustion process generates hot flue gases that in turn produce steam in the heat exchange sections of boilers. The steam is used to generate electricity in the turbine/generator. Electricity production from biomass is expected to continue to be used as base load power. Most wood and wood products industries obtain electricity and thermal energy from biomass.

(ii) Principal Markets and Distribution Methods

The Valley Power Facility located at Drayton Valley, Alberta is a biomass facility which serves the Alberta market. Electricity is transmitted from the generating facility to the delivery point via transmission lines, and then connects to the grid.

(iii) Material Facilities

The biomass Valley Power Facility is not material to APUC. During 2009, it was determined that the Valley Power Facility no longer fit APCo's preferred asset profile, no longer considered strategic to the ongoing operations of APCo and it decided commence a process to to dispose of its 50% ownership in the Drayton Valley Facility. As a result, the Facility was written down to estimated net realizable value.

(i) Thermal - Landfill Gas Generation

(i) Production Method

Landfill gas sites ("**LFG**") produce methane gas from the decomposition of organic materials which can be burned to produce energy. Typically, landfill gas is collected by drilling gas wells into the landfill at predetermined locations. The wells are connected by an underground pipe system that deliver the gas to the processing and conversion stations where it is piped off to engines or turbines to be burned to generate electricity.

(ii) Principal Markets and Distribution Methods

The principal market for the electricity from the LFG Facilities of APUC is the PJM Interconnection Market serving New Jersey. The electricity generated by the Balefill and Kingsland Facilities is transmitted to the purchaser, the system operator, via overhead transmission lines, who then distributes it through the PJM Interconnection grid. In addition, these Facilities sell generating capacity into the PJM market. Landfill gas produced at the Kearny Facility is sold to the Public Service Electric and Gas Company utility for distribution.

(iii) Material Facilities

The LFG Facilities of APCo, namely the Balefill, Kingsland and Kearny Facilities in New Jersey and the Nashville facility in Tennessee, are not material to APUC. During 2009, it was determined that the LFG Facilities no longer fit APCo's preferred asset profile, no longer considered strategic to the ongoing operations of APCo and it decided to commence a process to dispose of its investments in its remaining LFG Facilities. As a result, the LFG Facilities were written down to estimated net realizable value.

3.3 Revenues for Fiscal 2008 and 2009

As at March 31, 2010, APUC owned, directly or indirectly, debt, equity and royalty and other interests in 55 power generation facilities including those identified in "*Other Interests in Energy Related Developments*" and 19 regulated water distribution and wastewater facilities. For the year ended December 31, 2009, APUC derived approximately 71.7% of its revenues from its interests in power generation facilities (74.1% in 2008), 7.7% of its revenues from waste disposal fees (7.3% in 2008) and 20.6% of its revenues from its interests in regulated water distribution and wastewater facilities (16.5% in 2008).

3.4 Additional Description of the Business of APUC

(a) Specialized Skill and Knowledge

The senior executives of APUC have extensive contacts in the independent power industry in Canada and the United States. APCo, as well, has 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.

The Energy Services Business requires specialized knowledge of the NE-ISO 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 Energy Services Business.

(b) 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 the Fund or operate according to more flexible conditions.

APUC will access public markets to finance projects and acquisitions if funds are not immediately available.

Significant deregulation and opening of competition is occurring in the electricity marketplace. APCo is in a strong competitive position since, for new generation, small hydroelectric is the lowest cost producer, after industrial co-generation, in relation to total costs, and is the lowest cost producer with respect to variable production costs.

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 power is not subject to commodity fuel price volatility or risk. In addition, the generation of hydroelectric power does 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.

Deregulation has increased demand for privately generated power from a variety of sources including fossil fuels, waste, wind and water. Taking into account capital costs, wind power is generally more expensive than traditional forms of generated power. Fossil fuels are harmful to the environment; and waste burning power generation requires producers to abide by stringent and costly environmental regulations.

With deregulation and opening of competition in the electricity marketplace, there will 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.

Though programs and policies are evolving at all government levels, the trading of greenhouse gas credits created by renewable energy projects is seen as part of the eventual solution.

APCo 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.

APCo 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. APCo will continue to actively pursue development projects which provide the opportunity to exhibit accretive growth. APCo 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.

(c) Environmental Matters

The Facilities encompass operations which require adherence to environmental standards imposed by regulatory bodies through licences, permits, policies and legislation. Failure to operate the Facilities in strict compliance with these regulatory standards may expose the Facilities to claims, clean-up costs 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, 2009. 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. APCo has assessed the likelihood of these risks becoming a contingent environmental liability as remote; therefore APCo has not recorded any contingent liabilities on its financial statements.

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. In the aggregate, the departments comprise 7 full time equivalent positions based out of head office and have an annual budget of approximately $1.0 million, which includes wages, travel and other costs. Facility specific permitting and compliance expenses are direct operating expenses of each facility and are excluded from these expenses.

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. Each of APUC's businesses have 24 hour, 365 day emergency response and spill procedures in place in the event there is an oil or chemical spill.

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, 2009.

(i) Power Generation

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; 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, 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. 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.

(ii) Water Utilities

Liberty Water 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 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 Water 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 Water 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.

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.

Specific Environmental Risks

Greenhouse Gas Initiatives:

Several Northeastern US States have formed a coordination group to develop a multi state green house gas mitigation action plan. This group, RGGI has received backing from several states where APCo operates facilities including Connecticut and New Jersey. 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 will be implemented to regulate CO2 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. As such APCo will be required to purchase approximately 250,000 tons of CO2 allowances per year, equivalent to the total annual CO2 emissions from the Windsor Locks Facility for the 2009 to 2012 fiscal years. APCo is entitled to apply for allowances and/or purchase allowances at a base price of $2.00 per tonne from the state of Connecticut. APCo submitted an application on October 31, 2008 for allowances under the available programs. For 2010, APCo has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks facility to be between $0.2 and $0.4 million.

Seven U.S. States (including Arizona and California) and four Canadian provinces (including Manitoba, Ontario and Quebec) have formed a group called WCI. This group recently released details of its Regional Cap-and-Trade Program, which is scheduled to start on January 1, 2012. 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 others in Ontario which could be impacted by this program. As this process has just begun, it is too early to determine the potential financial impact on APCo and means available to mitigate this financial impact, if any.

The CDP is an independent non-profit organization that represents institutional investors managing over $57.0 trillion of assets. The CDP is specifically working to encourage companies world wide to quantify and disclose their greenhouse gas emissions and to outline what actions the companies are taking to address climate change risk, both from potential physical impacts but also from regulatory changes that may result in an effort to address climate change.

APCo submitted a baseline greenhouse gas emissions inventory to the CDP at the end of June 2008. 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.

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, 2009.

Regimes that Could Impact APUC

Renewable Energy Division:

As a result of certain legislation passed in Quebec (Bill C93), APCo is undertaking technical assessments of its hydroelectric facility dams owned or leased within the Province of Quebec. This is discussed in greater detail within the analysis of results in the Renewable Energy Division.

The province of Ontario is considering enacting new legislation similar to Bill C93. APCo operates four 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 expected capital costs related to the Quebec facilities, as there are fewer facilities in Ontario and they are of newer construction.

Water Utilities:

Liberty Water owns and operates the LPSCo facility, a water distribution and waste-water treatment utility servicing the City of Litchfield Park***,*** and parts of the City of Goodyear, the City of Avondale and the County of Maricopa, Arizona, 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 LPSCo 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, LPSCo closely 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 LPSCo. EPA's monitoring and control efforts have not indicated that the concentrations are being reduced or fully captured. Additional remedial efforts by the EPA to stop advancement and reduce TCE concentrations are underway. In the event that any wells exceed EPA permitted TCE level, LPSCo 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 of removal of a well, there would remain sufficient production and reservoir capacity within the balance of the water distribution system to adequately service the needs of all of LPCSo's customers. In addition, LPSCo has identified alternate sites where replacement wells can be established to replace this lost capacity. The cost of establishing a new well is estimated to be between $2.0 million and $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, volume of water available at the new site, and acquisition of land and groundwater rights. Liberty Water does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.

Regimes that Could Benefit APUC

Following the recent US presidential election, the Obama administration has made a significant shift in US policy regarding climate change legislation and regulation. President Obama has made a clear commitment 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

(d) Employees

APUC has 9 employees involved in the management of the corporation. APCo currently has 70 employees who are involved in the operation of the renewable energy facilities, 23 employees who provide technical, environmental and safety services to APUC, and an additional 54 employees through its subsidiaries who are involved in the operations of the thermal Facilities. APT (including its subsidiaries) currently has 27 employees who are involved in the management of APCo. AES has 4 employees. Labour relations have been stable to date and there has not been any disruption in operations as a result of labour disputes with employees. With the exception of 45 employees at the EFW Facility and 6 employees at the Tinker Facility, the employees of APUC entities are non-unionized. In addition, Liberty Water currently has approximately 119 employees.

(e) Foreign Operations

For 2009, 60% of the gross revenue of APUC was generated in the United States. As at March 31, 2009, APUC has interests in 55 facilities located in the United States, including 19 water distribution and wastewater treatment facilities.

Currency fluctuations may affect the cash flow that APUC will realize from its operations, as certain APUC Businesses sell electricity in the United States and receive proceeds from such sales in US dollars. Such APUC Businesses also incur costs in US dollars.

(f) Intangible Properties

The “Algonquin” name and trademark and related marks and designs are licenced to APUC by APC under a non-exclusive, royalty-free trademark licence agreement dated December 23, 1997 between APC and APUC. Subject to the terms of the licence agreement, this licence will remain in effect for as long as the Management Agreement is in effect. APUC, by using the “Algonquin” name, has the benefit of the goodwill and recognition associated with APC and its affiliates’ use of the “Algonquin” name in the energy sector for the past twelve years.

The trademark “Liberty Water” has been registered to Liberty Water Co., and the water drop logo for Liberty Water has also been registered as a service mark to Liberty Water Co. The trademark and water drop logo have been licensed to the subsidiaries of Liberty Water Co. Also, as discussed in “*Liberty Water Chain*” above, these subsidiaries have trade name, business name or “doing business as” registrations that allow them to conduct business under the name “Liberty Water”. These registrations are significant to the brand name recognition of the APUC Business that is Liberty Water.

(g) Cycles and Seasonality

Based on the type of PPAs in place at all of the Facilities in which APUC has an interest, the revenue generated by the Facilities is proportional to the amount of electrical energy generated. In addition, the amount of energy generated at the hydroelectric facilities is dependent upon available water flows. Accordingly, APUC’s revenues are affected by low and high water flow caused by seasonal rains and melts, with the result that revenues are higher in the spring and fall and are lower in the summer and winter. Engineering studies have been undertaken to assess the amount of energy which can be expected to be generated from each facility on an average annual basis. Furthermore, the majority of the Facilities have significant operating histories with which to compare the theoretical estimates in the engineering studies. Due to geographic diversity of the Facilities, the variability of total revenues is 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 St. Leon 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 St. Leon Facility may be different and distributable cash could be impacted.

(h) Customers

The APUC Businesses derive their revenues principally from the sale of electricity to large utilities. For the twelve months ended December 31, 2009, APUC Businesses’ revenues were derived as follows: CL&P - approximately 18%; Manitoba Hydro - approximately 15%; Hydro Québec - approximately 17%; PG&E – approximately 12%; regulated water distribution and wastewater treatment facilities – approximately 21%; and others - approximately 17%.

(i) Economic Dependence

The largest customer on a percentage basis is CL&P which totalled 18% of gross revenues in the year ended December 31, 2009. This customer maintains a BBB S&P rating and receivables are invoiced monthly and generally collected within 30 days.

Similarly, the third largest customer on a percentage basis is Manitoba Hydro which totalled 10.6% of gross revenues in the year ended December 31, 2009; however, this customer maintains an AA S&P rating and receivables are invoiced monthly and generally collected within 20 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.

(j) Social or Environmental Policies

APUC has safety and environmental compliance policies in place. These policies have been communicated with staff, and have been incorporated into APUC's Safety Mission Statement and Employee manual. APUC's Safety Mission Statement is to:

1. uphold Public Safety at all Facilities;
2. uphold Employee Safety in the work-place;
3. uphold Environmental Compliance;
4. uphold Regulatory Compliance;
5. maintain Employee Job Satisfaction;
6. foster Open Communication To Achieve Company Guidelines;
7. ensure Long Term Integrity of Client's Assets; and
8. maximize Client Revenue on Facilities.

APUC has an Environmental, Health and Safety Group that reports independently to the President. 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.

3.5 Risk Factors

The following are certain risk factors relating to the business of APUC. 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.

Treasury Risk Management

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

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

Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC Businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 45% of EBITDA and 60% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in increased reported revenue from U.S. operations of approximately $9.6 million and increased reported expenses from U.S. operations of approximately $6.4 million or a net impact of $3.2 million ($0.035 per Common Share) on an annual basis.

This risk has historically and primarily been managed through the use of forward contracts as it required U.S. dollar cash inflows to meet Canadian dollar cash outflows. As a result of the current business strategy and lower payout ratio, APUC has determined that the prior practice of hedging 100% of its U.S. currency exposure is no longer appropriate and is taking steps to eliminate its existing forward currency contract program and during the quarter ended December 31, 2009, APUC terminated forward contracts of $37.2 million for net proceeds of $0.1 million. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes. For the year ended December 31, 2009 APUC realized a $0.3 million loss on forward contracts settled during the period.

The following chart sets out the amount of foreign exchange forward contracts outstanding as at December 31, 2009, hedge proceeds and average hedged rates over the term of the contracts:

	Total	2010	2011	2012	2013
Total U.S. $ Hedged	$39,760	$—	$26,450	$12,560	$ 750
Total Can. $ Proceeds	$40,460	—	26,793	12,864	803
Average Hedged Rate	$ 1.018	n/a	$ 1.013	$ 1.024	$1.070
Unrealized Gain (loss)	$ (1,469)	n/a	(1,084)	(391)	6
Impact of a $0.10 move in exchange rates	$ 3,976	n/a	$ 2,645	$ 1,256	$ 75

Based on the fair value of the forward contract using the exchange rates as at December 31, 2009, the exercise of these forward contracts will result in the use of cash of $1.1 million in fiscal 2011 and result in the use of cash of $0.4 million for the remainder of the hedged period beyond 2011. Assuming a decrease in the strength of the US dollar relative to the Canadian dollar of $0.10 at December 31, 2009, with a corresponding increase in the forward yield curve, the fair value of the outstanding forward exchange contracts would increase by $4.0 million, resulting in the generation of additional cash of $1.6 million in fiscal 2011, and the generation of $0.9 million in cash for the remainder of the hedged period beyond 2011.

Market price risk

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

Subsequent to December 31, 2009, as a result of the acquisition of the Energy Services Business on February 4, 2010, APCo provides the short-term energy requirements to various customers at fixed rates. These customers include energy sales to a town in New Brunswick, Standard Offer Service contract with three local municipal electric utilities in northern Maine, and a series of direct energy contracts with commercial buyers also in northern Maine. The energy requirements of these customers are estimated at approximately 150,000 MW-hrs on an annualized basis. While the Tinker Assets are expected to provide the majority of the energy required to service these customers, the Energy Services Business anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy. In the event that the Energy Services Business was required to purchase all of its energy requirements at ISO NE spot rates, each $10.00 change per MW-hr in the market prices in ISO NE would result in a change in expense of $1.5 million on an annualized basis.

This risk is mitigated though the use of short term energy hedges contracts. APCo has committed to acquire 12,500 MW-hrs of energy over the next 13 months at an average rate of approximately $75 per MW-hr.

Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its trade receivables. APUC does not believe this risk to be significant as approximately 90% of APCo Renewable Energy division's revenue, approximately 80% of APCo Thermal Energy division's revenue, and over 65% of total revenue 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 following chart sets out APCo's significant counterparties, their credit ratings and percentage of total revenue associated with the counterparty:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Manitoba Hydro	AA	19,800	29%
Hydro – Quebec	A+	21,700	32%
Ontario Electricity Financial Corporation	A+	10,800	16%
Public Service Company of New Hampshire	BBB	4,400	7%
National Grid	A-	3,500	5%
Total		**$ 60,200**	**88%**
Thermal Energy Division			
Connecticut Light and Power Company	BBB	23,200	29%
Pacific Gas and Electric Company	BBB+	16,300	20%
Ahlstrom	1R3 **	11,700	15%
Regional Municipality of Peel	AAA	14,500	18%
Total		**$ 65,700**	**82%**

* Ratings by Standard & Poor's as of January 2010
** Ratings by Dunn & Bradstreet as of February 2010

The remaining revenue is primarily earned by Liberty Water. In this regard, the credit risk related to Liberty Water accounts receivable balances of US $2.9 million is spread over approximately 68,000 customers, resulting in an average outstanding balance of less than $50.00 per customer. Liberty Water has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

Interest rate risk

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

(a) Power Generation

APCo's project debt at the Long Sault Rapids and Chuteford Facilities are subject to a fixed rate of interest and thus are not subject to interest rate risk.

The Senior Credit Facility had a balance of $94.0 million as at December 31, 2009. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.9 million annually. The Fund has fixed for floating interest rate swaps in an amount of $100.0 million which fix the interest expense on $100.0 million of borrowings at approximately 4.125% for 2010. This reduces volatility in the interest expense on this debt. The financial impact of any changes in interest rates are partially offset between the change in interest expense and the change in the underlying value of the interest rate swap. At December 31, 2009, the mark to market value of the interest rate swap was a net $3.3 million liability (December 31, 2008 – net $5.5 million liability).

APCo's project debt at the St. Leon Facility had a balance of $70.5 million as at December 31, 2009. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.7 million annually. Although the underlying debt with the project lenders carries variable rate of interest tied to the Canadian bank's prime rate, APCo has entered into a fixed for floating interest rate swap on this project specific debt until September 2015 which mirrors the underlying debt's interest and principal repayment schedule. This minimizes volatility in the interest expense on this debt. The financial impact of interest rate changes are effectively offset between the change in interest expense and the change in value of the interest rate swap. APCo has effectively fixed its interest expense on its senior debt facility at 5.47%. At December 31, 2009, the mark to market value of the interest rate swap was a net liability of $5.0 million (December 31, 2008 – liability of $11.3 million).

APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2009. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.2 million annually.

(b) Water Utilities

Liberty Water's project debt at the Litchfield and Bella Vista Facilities are subject to a fixed rate of interest and thus is not subject to interest rate risk.

Liquidity risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due. APUC's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

APUC currently pays a dividend of $0.24 per 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 their judgment, ensure APUC's long-term success. Based on the current level dividends paid during the year ended December 31, 2009, cash provided by operating activities exceeded dividends declared by 2.6 times.

As at December 31, 2009, APUC had cash on hand of $2.8 million and $51.3 million available to be drawn on the Senior Credit Facility. The term of the Senior Credit Facility matures on January 14, 2011. Subsequent to December 31, 2009, APUC initiated discussions with its senior lenders with regards to entering into a new multi-year term senior debt facility. See "*Debt of APUC*" in "*Capital Structure*" for a more detailed discussion and chart of the funds available to APUC and its subsidiaries under its Senior Credit Facility.

The Senior Credit Facility and project specific debt total approximately $244.8 million. In the event that APUC was required to replace the Senior Credit Facility and project specific debt with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment into the company may be negatively impacted. APUC attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

The cash flow generated from several of APUC's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regards 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. In this regard, a discussion of this risk is set out as follows:

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

APCo's Windsor Locks facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $0.8 million on an annual basis.

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

Risk of Default under Senior Credit Facility

As security for repayment of the Senior Credit Facility, APCo has, among other things, pledged the shares of certain of its subsidiaries. In addition to the amount outstanding under the Senior Credit Facility as described above, APCo has posted certain letters of credit totaling $33.1 million as security for obligations of the APUC Businesses. The terms of the Senior Credit Facility require APCo to pay a standby charge of 0.25% on the unused portion of the revolving credit facility and maintain certain financial covenants.

The Senior Credit Facility is secured by, among other things, a fixed and floating charge over all the entities owned by APUC. If the Senior Credit Facility goes into default, or is not renewed or refinanced when due, there is a risk that the lenders could exercise their security. If the Senior Credit Facility is not renewed or refinanced on reasonable terms, APUC's earnings could be negatively impacted.

Project Debt

The cash flows from several of the Facilities are subordinated to project debt at the specific Facility. There is a risk that any particular loan may go into default if there is a breach in complying with such covenants and obligations resulting in the lender realizing on its security and, indirectly, causing APUC to lose its investment in such Facility.

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. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter.

Mechanical and Operational Risks

APUC is entirely dependant upon the operations and assets of APUC's businesses. Accordingly, dividends to shareholders are dependent upon the profitability of each 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 the Liberty Water 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.

These risks are mitigated through the diversification of APUC's operations, both operationally (APCo and Liberty Water) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. In addition, APCo's existing long term PPAs minimize the risk of reductions in average energy pricing.

Asset Retirement Obligations

APUC completes periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC considers the contractual requirements outlined in its 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 estimating the fair value of such obligations. Based on its assessments, APUC does not have any significant retirement obligation liabilities and has not recorded any liability in its financial statements.

(a) Power Generation

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

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 Renewable Energy division's 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 APCo Thermal Energy division's EFW facility owns the property on which its facility operates. EFW's current waste incineration agreement expires in 2012 with two five year options to extend. While APCo anticipates being in a position to renew or extend the existing contract in 2012, in the event that APCo is unable to renew or extend the agreement, APCo may choose to close the facility but has no legal obligation to remove the assets. Under the terms of the contract, the responsibility for removal of the bulk of any hazardous material generated in the operation of the Facility remains with EFW's primary customer. As such, the potential expense to bring the facility in line with current environmental standards in the event it is eventually closed has been assessed as insignificant based on the quantification of costs to remediate the facility, expectation that the existing contract can be extended or renewed and that the potential timing of such an event, although unlikely, would be well in the future.

(b) Water Utilities

Liberty Water's facilities operate under agreements with a state or municipal regulator to provide the sole water distribution and/or wastewater treatment services in its area of operations, as set out in the agreements. In general, these 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 Water 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 Water is allowed to earn a return on its investment.

Environmental Risks

See "*Environmental Matters*" in "*Additional Description of the Business of APUC* ."

Litigation risks and other contingencies

The Fund 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.

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.

Tax risks associated with the Unit Exchange Offer

There is a possibility that the Canada Revenue Agency could successfully challenge the tax consequences of the Unit Exchange or prior transactions of Hydrogenics or that legislation could be enacted or amended resulting in different tax consequences from those contemplated in the Unit Exchange Offer 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.

Obligations to serve

Liberty Water's utility facilities may be 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 Water may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

Regulatory Climate and Permitting Risks

(a) Power Generation

Profitability of APUC Businesses will be in part dependent upon the continuation of a favourable regulatory climate with respect to the continuing operations and the future growth and development of the independent power production industry as a whole and, in particular, with respect to the hydroelectric power segment of the industry. Should the regulatory regime be modified in a manner which adversely affects the treatment of such facilities, including increases in taxes and permit fees, distributable cash to Unitholders may be adversely affected.

The operation of hydroelectric facilities is highly regulated. For example, in the case of hydroelectric generating facilities, water rights are generally owned by government and government agencies reserve the right to control water levels. 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 electrical generating facilities. 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.

The US Facilities obtain certain benefits and exemptions because of their Qualifying Facility status (" **QF Status**") under PURPA. If any facility were to lose its QF Status, the Facility would no longer be entitled to the exemptions and benefits thereof. Loss of QF Status may also require the Facility to cease selling electricity at the rates set forth in the existing PPAs to the extent they exceed current short run Avoided Costs. Under certain circumstances, loss of QF Status on a retroactive basis could lead to, among other things, claims by an electrical utility's end user customers for a refund of payments previously made.

(b) Water Utilities

Liberty Water's facilities are highly regulated and are subject to rate settings by state regulators, and rates charged by these facilities may be reviewed and altered by the State regulatory authorities from time to time. The operating companies are regulated utilities subject to the full regulation of the public utility commissions for 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 operate under cost-of-service regulation as administered by these state authorities. The utilities use a historic test year subject to certain adjustments for known and measureable changes 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 the reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. These regulatory bodies have the authority to establish the allowed rate of return on approved rate base and also determine which investments are approved for inclusion in the rate base which in both cases can affect the profitability of the division. If the utilities are unable to obtain government approval of requested rate increases, or if rate increases are untimely or inadequate to cover capital investments and to recover expenses, profitability could be affected.

Federal, state and local environmental laws and regulations impose substantial compliance requirements on water and wastewater utility operations. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements. Utility services facilities are also subject to State and Federal permits, discharge parameters and other environmental requirements. Discharge and treatment requirements may change from time to time.

Water and wastewater 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 Water, and while Liberty Water 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 Water regularly works with these authorities to manage the affairs of the business.

Dependence upon APUC Businesses

APUC is entirely dependent upon the operations and assets of APUC Businesses. 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 or distributions.

(a) Power Generation

The profitability of APCo's Businesses may be affected by expiry of the present long-term PPAs to which certain of APCo's Businesses are a party.

(b) Water Utilities

US 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.

Water distribution and wastewater treatment facilities could also 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 Water, and while Liberty Water 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.

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.

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.

(a) Power Generation

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 2008 for a term of 3 years, until 2011.

(b) Liberty Water

All employees of Liberty Water and their material subcontractors are non-unionized.

Dependence Upon Key Customers

The customers that currently purchase power from APUC's Facilities are large utilities. See the summaries of the contracts in Schedules A, B and C. If, for any reason, such customers were unable to fulfill their contractual obligations under the PPAs, distributable cash available to Unitholders would decline.

Potential Conflicts of Interest

As discussed in "*Developments in Fiscal 2009*" in "*Three Year History*" above, agreement was reached on December 21, 2009 to internalize management. As discussed, the consideration payable for such internalization is subject to APUC's shareholder approval. Unitholders had previously been dependent on APMI for the administration of the Fund and for management and operation of the Facilities. Since December 21, 2009, management of the Fund (and by name change APCo) has been conducted by officers of APUC. There may be situations in which conflicts of interest may arise between certain officers of APUC who are also currently principals of APMI, in relation to the interests of APUC. Transactions involving related parties, including APMI and 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, 2009.

Climate and Seasonal Fluctuations

(a) Power Generation

Based on the type of PPAs in place at all of the Facilities in which APCo has an interest, the revenue generated by the Facilities is proportional to the amount of electrical energy generated.

Seasonal fluctuations and hydrology

The amount of energy generated at the hydroelectric facilities is dependent upon available water flows. Accordingly, revenues will be significantly affected by low and high water flows within the watercourses on which the facilities are located. Hydroelectric operations are impacted by seasonal fluctuations. These assets are primarily run-of-river and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. Further, the ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Engineering studies have been undertaken to assess the amount of energy which can be expected to be generated from each facility on an average annual basis. Furthermore, the majority of the facilities have significant operating histories with which to compare the theoretical estimates determined in the engineering studies. However, there can be no assurance that the historical water availability will remain unchanged or that no

material hydrologic event will impact the hydrologic conditions which exist within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized. Severe flooding could also damage the hydroelectric facilities. Insurance may partially but not entirely reduce this risk.

Wind resource

The strength and consistency of the wind resource available for the St. Leon Facility will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the St. Leon 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 St. Leon Facility may be different and profitability could be impacted.

(b) Water Utilities

For Liberty Water's water distribution Facilities, 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 Facilities 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 water distribution Facilities.

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.

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.

DIVIDENDS/DISTRIBUTIONS

4.1 Dividends/Distributions Declared for Fiscal 2007, 2008 and 2009

The total amount of cash dividends/distributions declared for Fiscal 2007, 2008 and 2009 were, respectively, $69.9 million, $57.8 million and $19.3 million. The amount of cash dividends / distributions declared for each Common Share of APUC/trust unit of the Fund for Fiscal 2007, 2008 and 2009 were, respectively, $0.92, $0.75 and $0.24. Effective January 1, 2010, APUC's Board established a quarterly dividend of $0.06 or $0.24 annually.

The Unit Exchange Offer completed on October 27, 2009 resulted in the unitholders of the Fund becoming shareholders of APUC. As such, the Board of APUC has the discretion to determine if and when dividends are declared and the amount that is paid to shareholders through any such dividends. As a CBCA corporation, the dividend policy must also comply with the requirements of the CBCA, including the satisfaction of the liquidity test contained therein.

The members of the board of directors adopted a dividend policy to provide sustainable dividends to shareholders to the extent that it is appropriate considering cash flow from operations, financial condition, financial leverage, working capital requirements and investment opportunities. Dividends were paid monthly to shareholders of record on the last business day of each calendar month with actual payment to be made to such shareholders on or about the 15th day of the following month, subject to any contractual restrictions on such dividends including any agreements entered into with lenders of APUC or its affiliates. Effective January 1, 2010, APUC changed to a quarterly dividend schedule subject to subsequent Board declarations each quarter. The first quarterly record date is expected to be March 31, 2010, with a payment date on or about April 15, 2010. The Board of APUC can modify the dividend policy from time to time in its discretion.

4.2 Dividend Policy and Restrictions

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*".

CAPITAL STRUCTURE

5.1 General Description of Capital Structure

(a) Common Shares

APUC is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series. The holders of Common Shares are entitled to dividends if, as and when declared by the board of directors of APUC, to one vote per Common Share at meetings of the holders of Common Shares and upon liquidation, dissolution or winding up of the Corporation to receive pro rata the remaining property and assets of APUC.

As at December 31, 2009, APUC had 93,064,120 issued and outstanding Common Shares on a fully diluted basis. As at March 26, 2010, APUC had 93,694,757 issued and outstanding Common Shares on a fully diluted basis. Subsequent to December 31, 2009, Series 1A Debentures valued at $2,573 were exchanged for 630,637 Common Shares. There are no preferred shares issued or outstanding.

Dividends

See discussion in "*Dividend Policy and Restrictions"* above.

(b) Convertible Debentures

APUC currently has outstanding three series of convertible debentures:

- a principal amount of $64,370 pursuant to 7.50% convertible unsecured subordinated debentures due November 33, 2014 at a price of $1,000 per debenture (the **"Series 1A Debentures"**);
- a principal amount of $59,967 pursuant to 6.35% convertible unsecured subordinated debentures due November 30, 2016 at a price of $1,000 per debenture (the **"Series 2A Debentures"**); and
- a principal amount of $63,250 pursuant to 7.00% convertible unsecured subordinated debentures due June 30, 2017 at a price of $1,000 per debenture (the **"Series 3 Debentures"**).

If all of the principal amount of the Series 1A Debentures, the Series 2A Debentures and the Series 3 Debentures (the " **APUC Debentures**") were converted by the holders thereof, an additional 40,830,923 Common Shares will be issued pursuant to the terms of the trust indenture (the "**Trust Indenture**") dated as of October 27, 2009 between the APUC and CIBC Mellon Trust Company (the " **Debenture Trustee**") with respect to the Series 1A Debentures and the Series 2A Debentures and the terms of the trust indenture (the "**Series 3 Trust Indenture**") dated as of December 2, 2009 between the APUC and the Debenture Trustee.

Series 1A Debentures:

In July 2004, the Fund issued 85,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on July 31, 2011 ("**Series 1 Debentures**"). The Series 1 Debentures bore interest at 6.65% per annum and were convertible into trust units of the Fund at the option of the holder at a conversion price of $10.65 per trust unit, being a ratio of approximately 93.9 trust units for each $1,000 principal. On October 27, 2009, there were 84,964 convertible debentures outstanding with a face value of $84,964.

Pursuant to the CD Exchange Offer, on October 27, 2009, $63,755 of the outstanding Series 1 Debentures was exchanged for the Series 1A Debentures in a principal amount of $66,943. The Series 1A Debentures pay interest semi-annually in arrears on January 1 and July 1 each year and are convertible into shares of APUC at the option of the holder at a conversion price of $4.08 per Common Share, being a ratio of approximately 245.1 Common Shares for each $1,000 principal. The Series 1A Debentures may not be redeemed by APUC prior to January 1, 2011. During the period of January 2, 2011 until January 1, 2012, the debentures may be redeemed by APUC if the underlying trust unit price is equal to or exceeds a price of $5.10 (125% of the conversion price of $4.08). During the period of January 2, 2012 until the debentures' maturity, APUC can redeem the debentures for 100% of the face value of debenture with cash, or for 105% of the face value of debenture with additional Common Shares. The remaining Series 1 Debentures having a face value of $21,209, not converted to Series 1A Debentures pursuant to the CD Exchange Offer, were exchanged for 6,607,027 Common Shares.

Currently, as at March 26, 2010, there were 64,370 Series 1A Debentures outstanding with a face value of $64,370.

Series 2A Debentures:

In November 2006, the Fund issued 60,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on November 30, 2016 ("**Series 2 Debentures**"). The Series 2 Debentures bore interest at 6.2% per annum and were convertible into trust units of the Fund at the option of the holder at a conversion price of $11.00 per trust unit, being a ratio of approximately 90.9 trust units for each $1,000 principal. During the three months ended December 31, 2009 and prior to October 27, 2009, Series 2 Debentures valued at $33,000 were exchanged into 3,000 trust units. These trust units were converted to Common Shares of APUC as a result of the Unit Exchange. On October 27, 2009, there were 59,967 Series 2 Debentures outstanding with a face value of $59,967.

Pursuant to the CD Exchange Offer, on October 27, 2009, all of the outstanding Series 2 Debentures were exchanged for Series 2A Debentures in a principal amount of $59,967. The Series 2A Debentures pay interest semi-annually in arrears on April 1 and October 1 each year and are convertible into Common Shares at the option of the holder at a conversion price of $6.00 per Common Share, being a ratio of approximately 166.7 Common Shares for each $1,000 principal. The Series 2A Debentures may not be redeemed by APUC prior to January 1, 2011. During the period of January 2, 2011 until January 1, 2012, the debentures may be redeemed by APUC if the underlying trust unit price is equal to or exceeds a price of $7.50 (125% of the conversion price of $6.00). During the period of January 2, 2012 until the debenture's maturity, APUC can redeem the debentures for 100% of the face value of debenture with cash, or for 105% of the face value of debenture with additional Common Shares. On December 31, 2009, there were 59,967 Series 2A Debentures outstanding with a face value of $59,967.

Series 3 Debentures:

On December 2, 2009, APUC issued 63,250 Series 3 Debentures. APUC received net proceeds of $60.7 million after underwriting expenses and before additional issuance costs (gross proceeds of $63.3 million). The Series 3 Debentures bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year, and are convertible into Common Shares at the option of the holder at a conversion price of $4.20 per Common Share, being a ratio of approximately 238.1 Common Shares for each $1,000 principal. The Series 3 Debentures may not be redeemed by APUC prior to December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 Debentures may be redeemed by APUC only if the underlying Common Share price is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 Debentures' maturity, APUC can redeem the Series 3 Debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 Debentures with additional Common Shares. On December 31, 2009, there were 63,250 Series 3 Debentures outstanding with a face value of $63,250.

APUC may, however, from time to time, without the consent of the holders of the APUC Debentures, issue additional debentures. For a complete description of the APUC Debentures, reference should be made to the Trust Indenture and the Series 3 Trust Indenture, copies of which are available on www.sedar.com.

Conversion Privilege

The Series 1A Debentures are convertible at the holder's option into fully paid, non-assessable and freely-tradeable Common Shares at any time prior to 5:00 p.m. (Toronto time) on the earlier of November 30, 2014 (the "**Series 1A Maturity Date**") and the business day immediately preceding the date specified by APUC for redemption of the Series 1A Debentures, at a conversion price of $4.08 per Common Share (the "**Series 1A Conversion Price**") being a ratio of approximately 245.1 Common Shares per $1,000 principal amount of Series 1A Debentures. The Series 1A Debentures bear interest from the date of issue at 7.50% per annum, which will be payable semi-annually on July 1 and January 1 in each year, which commenced on January 1, 2010 (each, a "**Series 1A Interest Payment Date**").

The Series 2A Debentures are convertible at the holder's option into fully paid, non-assessable and freely-tradeable Common Shares at any time prior to 5:00 p.m. (Toronto time) on the earlier of November 30, 2016 (the "**Series 2A Maturity Date**") and the business day immediately preceding the date specified by APUC for redemption of the Series 2A Debentures, at a conversion price of $6.00 per Common Share (the "**Series 2A Conversion Price**") being a ratio of approximately 166.7 Common Shares per $1,000 principal amount of Series 2A Debentures. The Series 2A Debentures bear interest from the date of issue at 6.35% per annum, which will be payable semi-annually on April 1 and October 1 in each year, commencing on April 1, 2010 (each, a "**Series 2A Interest Payment Date**").

The Series 3 Debentures are convertible at the holder's option into fully paid, non-assessable and freely-tradeable Common Shares at any time prior to 5:00 p.m. (Toronto time) on the earlier of June 30, 2017 (the "**Series 3 Maturity Date**") and the business day immediately preceding the date specified by APUC for redemption of the Series 3 Debentures, at a conversion price of $4.20 per Common Share (the "**Series 3 Conversion Price**") being a ratio of approximately 238.1 Common Shares per $1,000 principal amount of Series 3 Debentures. The Series 3 Debentures bear interest from the date of issue at 7.0% per annum, which will be payable semi-annually on June 30 and December 31 in each year, commencing on June 30, 2010 (each, a "**Series 3 Interest Payment Date**").

Interest will be payable based on a 365-day year. At the option of APUC, subject to applicable law, APUC may deliver Common Shares to its agent who shall sell such Common Shares on behalf of APUC in order to raise funds to satisfy all or any part of APUC's obligations to pay interest on the APUC Debentures, but in any event, the holders of APUC Debentures shall be entitled to receive cash payments equal to the interest otherwise payable on the APUC Debentures.

No adjustment will be made for dividends on Common Shares issuable upon conversion or for interest accrued on APUC Debentures surrendered for conversion; however, holders converting their APUC Debentures are entitled to receive, in addition to the applicable number of Common Shares, accrued and unpaid interest in respect thereof for the period up to the date of conversion from: (a) the latest Series 1A Interest Payment Date (in the case of the Series 1A Debentures) or (b) the latest Series 2A Interest Payment Date (in the case of the Series 2A Debentures). Notwithstanding the foregoing, (a) no Series 1A Debentures may be converted on any Series 1A Interest Payment Date and during the five business days preceding January 1 and July 1 in each year, (b) no Series 2A Debentures may be converted on any Series 2A Interest Payment Date and during the five business days preceding April 1 and October 1 in each year, and (c) no Series 3 Debentures may be converted on any Series 3 Interest Payment Date and during the five business days preceding June 30 and December 31 in each year as the registers of the Debenture Trustee are closed during such periods.

Subject to the provisions thereof, the Trust Indenture and the Series 3 Trust Indenture provide for the adjustment of the Series 1A Conversion Price, the Series 2A Conversion Price and the Series 3 Conversion Price in certain events including: (a) the subdivision or consolidation of the outstanding Common Shares; (b) the distribution of Common Shares to holders of Common Shares by way of distribution or otherwise other than an issue of securities to holders of Common Shares who have elected to receive distributions in securities of APUC in lieu of receiving cash distributions paid in the ordinary course; (c) the issuance of options, rights or warrants to holders of Common Shares entitling them to acquire Common Shares or other securities convertible into Common Shares at less than 95% of the then Current Market Price (as defined below under "*Payment upon Redemption or Maturity*") of the Common Shares; and (d) the distribution to all holders of Common Shares of any securities or assets (other than cash distributions and equivalent distributions in securities paid in lieu of cash distributions in the ordinary course). There will be no adjustment of the Series 1A Conversion Price, the Series 2A Conversion Price or the Series 3 Conversion Price, in respect of any event described in (b), (c) or (d) above if, subject to prior

regulatory approval, the holders of APUC Debentures are allowed to participate as though they had converted their APUC Debentures prior to the applicable record date or effective date. APUC will not be required to make adjustments in either the Series 1A Conversion Price, the Series 2A Conversion Price or the Series 3 Conversion Price, unless the cumulative effect of such adjustments would change the Series 1A Conversion Price, the Series 2A Conversion Price or the Series 3 Conversion Price, as the case may be, by at least 1%.

In the case of any reclassification or change (other than a change resulting only from consolidation or subdivision) of the Common Shares or in case of any amalgamation, consolidation or merger of APUC with or into any other entity, or in the case of any sale, transfer or other disposition of the properties and assets of APUC as, or substantially as, an entirety to any other entity, the terms of the conversion privilege shall be adjusted so that each APUC Debenture shall, after such reclassification, change, amalgamation, consolidation, merger or sale, be exercisable for the kind and amount of securities or property of APUC, or such continuing, successor or purchaser entity, as the case may be, which the holder thereof would have been entitled to receive as a result of such reclassification, change, amalgamation, consolidation, merger or sale if on the effective date thereof it had been the holder of the number of Common Shares into which APUC Debenture was convertible prior to the effective date of such reclassification, change, amalgamation, consolidation, merger or sale.

No fractional Common Shares will be issued on any conversion of APUC Debentures, but in lieu thereof, APUC shall satisfy such fractional interest by a cash payment equal to the Current Market Price of such fractional interest.

Redemption and Purchase

Prior to January 1, 2011, the Series 1A Debentures may be redeemed at the option of APUC, in whole at any time or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the weighted-average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given exceeds 125% of the Series 1A Conversion Price.

On or after January 1, 2011 and prior to the Series 1A Maturity Date, the Series 1A Debentures may be redeemed by APUC, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest.

The Series 2A Debentures may not be redeemed by APUC (except in the case of a change of control) on or before January 1, 2011. Thereafter, but prior to January 1, 2012, the Series 2A Debentures may be redeemed at the option of APUC, in whole at any time or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the weighted-average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given exceeds 125% of the Series 2A Conversion Price.

On or after January 1, 2012 and prior to the Series 2A Maturity Date, the Series 2A Debentures may be redeemed by APUC, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest.

The Series 3 Debentures may not be redeemed by APUC (except in the case of a change of control) on or before December 31, 2012. Thereafter, but prior to December 31, 2014, the Series 3 Debentures may be redeemed at the option of APUC, in whole at any time or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the weighted-average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given exceeds 125% of the Series 3 Conversion Price.

On or after December 31, 2014 and prior to the Series 3 Maturity Date, the Series 3 Debentures may be redeemed by APUC, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest.

APUC will have the right to purchase APUC Debentures in the market, by tender or by private contract subject to regulatory requirements; provided, however, that if an Event of Default (as defined below) has occurred and is continuing, APUC will not have the right to purchase APUC Debentures by private contract.

In the case of redemption of less than all of APUC Debentures, APUC Debentures to be redeemed will be selected by the Debenture Trustee on a *pro rata* basis or in such other manner as the Debenture Trustee deems equitable, subject to the consent of the TSX.

Payment upon Redemption or Maturity

On redemption or on the Series 1A Maturity Date, the Series 2A Maturity Date or the Series 3 Maturity Date, as applicable, APUC will repay the indebtedness represented by APUC Debentures which are to be redeemed or which have matured by paying to the Debenture Trustee in lawful money of Canada an amount equal to the principal amount of the outstanding APUC Debentures, together with accrued and unpaid interest thereon. APUC may, at its option, on not more than 60 days' and not less than 40 days' prior notice and subject to any required regulatory approvals, unless an Event of Default (as defined below) has occurred and is continuing, elect to satisfy its obligation to repay, in whole or in part, the principal amount of APUC Debentures which are to be redeemed or which have matured by issuing and delivering freely tradeable Common Shares to the holders of the APUC Debentures. The number of Common Shares to be issued will be determined by dividing the principal amount of the APUC Debentures which are to be redeemed by 95% of the Current Market Price of the Common Shares on the date fixed for redemption or the maturity date, as the case may be. No fractional Common Shares will be issued to holders of APUC Debentures but in lieu thereof APUC shall satisfy such fractional interest by a cash payment equal to the Current Market Price of such fractional interest.

The term "**Current Market Price**" is defined in the Trust Indenture to mean the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date of the applicable event.

Cancellation

All APUC Debentures converted, redeemed or purchased as aforesaid will be cancelled and may not be reissued or resold.

Subordination

The payment of the principal of, and interest on, the APUC Debentures is subordinated in right of payment, in the circumstances referred to below and more particularly as set forth in the Trust Indenture, to the prior payment in full of all Senior Indebtedness of APUC. "**Senior Indebtedness**" of APUC is defined in the Trust Indenture as all indebtedness of APUC, other than the APUC Debentures and any other debentures issued under the Trust Debenture, (whether outstanding as at the date of the Trust Indenture or thereafter created, incurred, assumed or guaranteed), and including, for greater certainty, claims of trade creditors of APUC, which by the terms of the instrument creating or evidencing the indebtedness, is not expressed to be pari passu with, or subordinate in right of payment to, APUC Debentures.

The Trust Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation or reorganization in connection with or as a result of an insolvency or bankruptcy proceeding or other similar proceedings relative to APUC, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding up of APUC, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of APUC, all creditors under any Senior Indebtedness will receive payment in full before the holders of APUC Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Fund Debentures or any unpaid interest accrued thereon.

In addition to the foregoing, pursuant to the terms of the Trust Indenture, neither the Debenture Trustee for, nor the holders of, APUC Debentures are entitled to demand or otherwise attempt to enforce in any manner, institute proceedings for the collection of, or institute any proceedings against APUC, including, without limitation, by way of any bankruptcy, insolvency or similar proceedings or any proceeding for the appointment of a receiver, liquidator, trustee or other similar official (it being understood and agreed that the Debenture Trustee and/or the holders of APUC Debentures are permitted to take any steps necessary to preserve the claims of the holders of APUC Debentures in any such proceeding and any steps necessary to prevent the extinguishment or other termination of a claim or potential claim as a result of the expiry of a limitation period), or receive any payment or benefit in any manner whatsoever on account of indebtedness represented by APUC Debentures other than as set forth in the Trust Indenture at any time when (i) an event of default (howsoever designated) has occurred and is continuing under the Senior Credit Facility, or (ii) an event of default (howsoever designated) has occurred under any other Senior Indebtedness and is continuing and, in each case, notice of such event of default has been given by or on behalf of the lender or lenders party to such Senior Indebtedness to the Fund or an affiliate thereof that is the borrower pursuant to such Senior Indebtedness (the "**Senior Indebtedness Postponement Provisions**").

The APUC Debentures are also subordinate to claims of creditors of APUC.

Put Right upon a Change of Control

Upon the occurrence of a change of control of APUC involving the acquisition of voting control or direction over 66 $^{2}/_{3}$% or more of the outstanding Common Shares by any person or group of persons acting jointly or in concert (a "**Change of Control**"), each holder of APUC Debentures may require APUC to purchase, on the date which is 30 days following the giving of notice of the Change of Control as set out below (the "**Put Date**"), the whole or any part of such holder's APUC Debentures at a price equal to 101% of the principal amount thereof (the " **Put Price**") plus accrued and unpaid interest to the Put Date.

If 90% or more in the aggregate principal amount of APUC Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered for purchase on the Put Date, the Fund will have the right to redeem all the remaining APUC Debentures on such date at the Put Price, together with accrued and unpaid interest to such date. Notice of such redemption must be given to the Debenture Trustee prior to the Put Date and as soon as possible thereafter, by the Debenture Trustee to the holders of APUC Debentures not tendered for purchase. The principal on APUC Debentures will be payable in lawful money of Canada or, at the option of the Fund and subject to applicable regulatory approval, by payment of Common Shares to satisfy, in whole or in part, its obligation to repay the principal amount of APUC Debentures.

The Trust Indenture contains notification provisions to the effect that:

(a) APUC will promptly give written notice to the Debenture Trustee of the occurrence of a Change of Control and the Debenture Trustee will thereafter give to the holders of APUC Debentures a notice of the Change of Control, the repayment right of the holders of APUC Debentures and the right of APUC to redeem un-tendered APUC Debentures under certain circumstances; and

(b) a holder of APUC Debentures, to exercise the right to require APUC to purchase its APUC Debentures, must deliver to the Debenture Trustee, not less than five business days prior to the Put Date, written notice of the holder's exercise of such right, together with a duly endorsed form of transfer.

APUC will comply with the requirements of Canadian securities laws and regulations to the extent such laws and regulations are applicable in connection with the repurchase of APUC Debentures in the event of a Change of Control.

Modification

The rights of the holders of the APUC Debentures as well as any other series of debentures that may be issued under the Trust Indenture may be modified in accordance with the terms of the Trust Indenture. For that purpose, among others, the Trust Indenture contains certain provisions which will make binding on all holders of APUC Debentures resolutions passed at meetings of the holders of APUC Debentures by votes cast thereat by holders of not less than 66 2/3% of the principal amount of the then outstanding Fund Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66 2/3% of the principal amount of the then outstanding APUC Debentures. In certain cases, the modification will, instead of or in addition to, require assent by the holders of the required percentage of APUC Debentures of each particularly affected series. Under the Trust Indenture, the Debenture Trustee has the right to make certain amendments to the Trust Indenture in its discretion, without the consent of the holders of APUC Debentures.

Events of Default

The Trust Indenture provides that an event of default (" **Event of Default**") in respect of the APUC Debentures will occur if certain events described in the Trust Indenture occur, including if any one or more of the following described events has occurred and is continuing with respect to the APUC Debentures: (i) failure for 15 days to pay interest on the APUC Debentures when due; (ii) failure to pay principal or

premium, if any, on the APUC Debentures, whether at maturity, upon redemption, by declaration or otherwise; or (iii) certain events of bankruptcy, insolvency or reorganization of APUC under bankruptcy or insolvency laws. Subject to the Senior Indebtedness Postponement Provisions, if an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall, upon the request of holders of not less than 25% in principal amount of the then outstanding APUC Debentures, declare the principal of (and premium, if any) and interest on all outstanding APUC Debentures to be immediately due and payable.

Offers for Debentures

The Trust Indenture contains provisions to the effect that if an offer is made for APUC Debentures which is a take-over bid for APUC Debentures within the meaning of the *Securities Act* (Ontario) and not less than 90% of the APUC Debentures (other than APUC Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the APUC Debentures held by holders of APUC Debentures who did not accept the offer on the terms offered by the offeror.

Priority of Debt

The APUC Debentures will be direct obligations of APUC and will not be secured by any mortgage, pledge, hypothec or other charge and will be subordinated to other liabilities of APUC. The Trust Indenture does not restrict AUC from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its assets to secure any indebtedness.

(c) Debt of APUC

Lines of Credit

APUC has available, through a subsidiary, a Senior Credit Facility provided by a syndicate of Canadian banks, which was renewed by the Fund on January 16, 2008. Under terms of the renewal, the Senior Credit Facility was extended for a three year term with a maturity date of January 14, 2011. The Senior Credit Facility consists of committed bank facilities of $192.75 million to accommodate future growth and acquisitions. The Senior Credit Facility contains covenants that may restrict APUC's ability to borrow on the facility as described below.

The Senior Credit Facility consists of a general operating facility of $20.0 million, provisions of letters of guarantee of approximately $33.1 million and the balance for acquisition funding purposes.

As of December 31, 2009, APUC had approximately $94.0 million outstanding under the Senior Credit Facility, all of which had been drawn down for acquisition or growth purposes. In addition, APUC has used the Senior Credit Facility to post (i) a letter of credit in the approximate amount of US$19.5 million in respect of the Sanger Facility; (ii) a $1.0 million letter of credit in respect of the Dickson Dam Facility; (iii) letters of credit for the EFW Facility totalling $5.4 million; (iv) letters of credit pursuant to the BCI Facility totalling $2.4 million; (v) letters of credit in connection with the St. Leon Facility totalling $1.7 million; (vi) letters of credit in connection with the Long Sault Rapids Facility totalling $1.2 million; and (vii) various other letters of credit required by the Fund entities totalling $0.9 million.

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries under the Senior Credit Facility previously arranged by the Fund:

	2009 Q4	2009 Q3	2009 Q2	2009 Q1	2008 Q4
Committed and available Senior Credit Facility	$179,600	$ 176,700	$ 189,050	$ 192,750	$ 192,750
Funds Drawn on Senior Credit Facility	(94,000)	(129,000)	(134,000)	(129,500)	(137,000)
Letters of Credit issued	(33,100)	(33,400)	(35,250)	(37,600)	(37,500)
Remaining available Senior Credit Facility	**$ 52,500**	**$ 14,300**	**$ 19,800**	**$ 25,650**	**$ 18,250**
Cash on Hand	2,800	7,700	6,900	900	5,900
Total liquidity and capital reserves	**$ 55,300**	**$ 22,000**	**$ 26,700**	**$ 26,550**	**$ 24,150**

As at and for the period ended March 31, 2010, APUC and the Fund are in compliance with the covenants under the Senior Credit Facility.

As at December 31, 2009, $94.0 million had been drawn on the Senior Credit Facility as compared to $137.0 million as at December 31, 2008. In addition to amounts actually drawn, there was $33.1 million in letters of credit currently outstanding as at December 31, 2009. As at December 31, 2009, APUC and its subsidiaries had $52.5 million of committed and available under the Senior Credit Facility remaining and $2.8 million of cash resulting in $55.3 million of total liquidity and capital reserves.

The term of the Senior Credit Facility matures on January 14, 2011. Subsequent to December 31, 2009, APUC initiated discussions with its senior lenders with regards to entering into a new multi-year term senior debt facility.

As at December 31, 2009, in addition to the liquidity and capital reserves noted above, APUC also had $40.0 million in short term investments available to complete the acquisition of three hydroelectric generating assets located in New Brunswick and Maine having a capacity of 36.8MW, most notably the 34.5MW Tinker Hydroelectric station located on the Aroostook River near the Town of Perth-Andover, New Brunswick.

As security for repayment of the Senior Credit Facility, the Fund has, among other things, provided a fixed and floating charge over all APUC Businesses and pledged the shares of certain Fund entities to the banking syndicate. As a requirement of the Senior Credit Facility, APUC has to maintain certain financial covenants. APUC is in material compliance with the terms of the agreements governing the Senior Credit Facility and no waiver of any breach has occurred thereunder.

Interest

While the Fund maintains a credit rating of triple B- ('BBB-') by Standard & Poors, any amounts outstanding under the Senior Credit Facility bears interest at a rate equal to the banker's acceptance or London Interbank Offered Rate (LIBOR) plus a margin of 0.95% with no additional margins. Interest is payable monthly. The unused portion of the Senior Credit Facility attracts an annual standby fee equal to 0.25% payable quarterly. These rates can decrease in the event the Fund's credit rating is upgraded. See "*Ratings*".

Redemption

The credit agreement in respect of the Senior Credit Facility stipulates that the amount outstanding under the Senior Credit Facility is due and payable on maturity (January 14, 2011).

5.2 Ratings

A subsidiary of APUC, the Fund, maintains a rating with Standard & Poor's (" **S&P**") as a requirement of its Senior Credit Facility. On January 22, 2010, S&P ratings services lowered its long-term corporate credit rating on the Fund to 'BBB-' from 'BBB' with a stable outlook. The January 22, 2010 rating did not impact the current terms and pricing available under the Senior Credit Facility. The Fund currently maintains a triple B- long-term corporate credit rating (BBB-). The Fund also carries a triple B- (BBB-) credit rating on its Senior Credit Facility.

In January 2010, S&P lowering its stability rating on the Fund to 'SR-3' from 'SR-2.' The outlook was changed to "stable" from "negative". The rating was subsequently withdrawn since APUC as the continuing public entity is a corporation and not an income trust. The January 22, 2010 stability rating and its withdrawal did not impact the current terms and pricing available under the Senior Credit Facility.

The income fund stability and sustainability rating system managed by **S&P** is intended to rank the stability of an income fund's cash distribution stream on the basis of volatility and sustainability. The scale utilized by S&P runs from SR-1 (Highest) to SR-7 (Very Low). A rating of 'SR-1' signifies the highest level of expected sustainability and the lowest level of expected variability in a fund's distribution stream relative to other rated Canadian income funds. Conversely, a rating of 'SR-7' indicates the highest degree of expected variability and the lowest degree of expected sustainability in distributions. Funds rated 'SR-2' are considered by S&P to have a very high level of cash distribution stability relative to other rated Canadian income funds.

S&P's issue credit rating is a current opinion of the creditworthiness of an obligor with respect to a specific financial obligation, a specific class of financial obligations, or a specific financial program (such as medium-term note programs and commercial paper programs). The rating takes into consideration the creditworthiness of guarantors, insurers, or other forms of credit enhancement on the obligation, as well as the currency in which the obligation is denominated. Long-term credit ratings are divided into several categories ranging from 'AAA', reflecting the strongest credit quality, to 'D', reflecting the lowest. Long-term ratings from 'AA' to 'CCC' may be modified by the addition of a plus or minus sign to show relative standing within the major rating categories.

According to S&P, an obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation.

Investors should be advised that the ratings provided by S&P are not recommendations to buy, sell or hold securities and are subject to revision or withdrawal at any time by S&P.

MARKET FOR SECURITIES

6.1 Trading Price and Volume

Common Shares

APUC's Common Shares have been listed and posted for trading on the TSX since October 28, 2009 under the symbol "AQN". On October 27, 2009, pursuant to the Unit Exchange Offer, all the Fund's trust units were exchanged for Common Shares of APUC that began to be publicly traded on the TSX while the Fund's trust units concurrently ceased trading on the TSX. Prior to October 27, 2009, the Fund's trust units were listed and posted for trading on the TSX since December 23, 1997 under the symbol "APF.UN".

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Common Shares and trust units on the periods indicated (as quoted by the TSX):

Monthly Information

	Trading of Shares*on the TSX		
Period	High ($)	Low ($)	Volume
2007			
January	9.90	8.81	4,962,163
February	9.25	8.82	3,845,924
March	9.08	8.25	5,053,703
April	9.42	8.25	9,079,774
May	9.42	8.72	3,651,096
June	8.87	8.33	2,901,758
July	9.20	8.40	2,507,383
August	9.00	8.38	2,629,370
September	9.04	8.55	1,506,153
October	9.17	8.59	2,391,390
November	8.74	7.25	4,748,945
December	8.41	7.54	3,467,298
2008			
January	8.40	7.10	3,179,456
February	7.67	7.05	3,795,282
March	7.79	6.40	6,469,392
April	8.00	7.38	4,337,038
May	7.99	7.41	3,529,051
June	8.28	7.60	2,680,075
July	7.92	7.01	2,391,322
August	7.48	7.00	2,259,679
September	7.15	4.50	4,824,320
October	5.93	2.30	14,505,231
November	3.10	2.32	8,486,497
December	2.58	1.76	10,518,416

Period	Trading of Shares*on the TSX		
	High ($)	Low ($)	Volume
2009			
January	2.89	2.36	4,715,642
February	2.79	2.49	2,464,368
March	2.57	2.11	3,739,580
April	3.08	2.35	6,563,900
May	3.18	2.78	5,729,217
June	3.61	2.96	4,695,357
July	3.88	3.18	5,535,283
August	3.85	3.56	5,423,704
September	3.66	3.32	6,277,214
October (1-27) *	3.55	3.37	8,291,077
October (28 -31)	3.58	3.54	1,291,473
November	3.53	3.32	7,403,713
December	4.13	3.51	6,864,570

* Prior to October 27, 2009, all trades were for trust units of the Fund.

Series 1A Debentures

APUC's Series IA Debentures have been listed and posted for trading on the TSX since October 28, 2009 under the symbol "AQN.DB". On October 27, 2009, pursuant to the Unit Exchange Offer, $63,755 of the Series 1 Debentures were exchanged for Series IA Debentures that began to be publicly traded on the TSX while the Series I Debentures concurrently ceased trading on the TSX. Prior to October 27, 2009, the Series I Debentures were listed and posted for trading on the TSX since July 20, 2004 under the symbol "APF.DB".

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 1A Debentures on the periods indicated (as quoted by the TSX):

Period	Trading of Series 1A Debentures * on the TSX		
	High $	Low $	Volume $100
2007			
January	105.49	102.00	16,800
February	107.50	103.00	7,730
March	104.97	102.00	8,340
April	105.00	102.00	10,020
May	104.75	103.00	9,330
June	104.75	102.00	5,190
July	105.00	99.51	6,700
August	103.89	100.00	8,970
September	101.99	100.00	4,530
October	101.00	98.51	9,360
November	101.00	99.90	11,400
December	100.99	98.50	7,950

Period	Trading of Series 1A Debentures * on the TSX		
	High	Low	Volume
	$	$	$100
2008			
January	101.00	98.51	11,830
February	101.00	99.51	9,020
March	102.76	100.01	17,460
April	103.89	99.50	10,620
May	101.99	99.25	20,070
June	100.50	100.25	9,600
July	102.00	100.25	10,810
August	100.51	100.06	7,330
September	103.50	99.90	9,660
October	100.00	75.00	18,790
November	93.00	77.50	14,340
December	88.98	85.00	12,730
2009			
January	94.00	88.00	13,670
February	93.94	91.75	20,260
March	97.00	91.51	13,040
April	98.00	96.00	9,700
May	100.00	98.25	7,940
June	102.50	99.18	48,210
July	106.00	100.00	63,800
August	107.25	104.80	36,420
September	105.30	104.30	22,730
October (1-27) *	105.00	102.00	107,110
October (28-31)	109.00	104.85	3,580
November	105.75	103.75	33,040
December	109.25	104.76	5,599

* Prior to October 27, 2009, all trades were for Series 1 Debentures of the Fund.

Series 2A Debentures

APUC's Series 2A Debentures have been listed and posted for trading on the TSX since October 28, 2009 under the symbol "AQN.DB.A". On October 27, 2009, pursuant to the Unit Exchange Offer, all of the Series 2 Debentures were exchanged for Series 2A Debentures that began to be publicly traded on the TSX while the Series 2 Debentures concurrently ceased trading on the TSX. Prior to October 27, 2009, the Series 2 Debentures were listed and posted for trading on the TSX since November 22, 2006 under the symbol "APF.DB.A".

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

Period	Trading of Series 2A Debentures* on the TSX		
	High	Low	Volume
	$	$	$100
2006			
November 22 – November 30	99.50	95.00	48,150
December	102.00	98.00	81,190
2007			
January	104.00	100.00	22,370
February	105.00	100.00	12,360
March	102.50	100.00	13,240
April	102.75	101.04	8,070
May	104.00	101.10	7,570
June	101.99	95.03	13,760
July	102.00	98.01	4,020
August	101.00	90.00	5,580
September	100.00	90.00	4,880
October	98.00	93.05	3,910
November	100.00	93.05	3,940
December	98.50	94.00	5,090
2008			
January	98.50	85.00	5,150
February	96.25	90.51	9,900
March	95.99	92.35	4,330
April	95.49	88.01	7,960
May	94.99	90.05	5,170
June	95.00	93.00	5,750
July	94.50	87.50	6,060
August	94.00	89.51	4,480
September	94.95	85.01	4,140
October	87.50	60.00	3,730
November	87.00	61.05	5,100
December	70.00	45.01	8,605
2009			
January	78.00	63.01	4,800
February	80.00	65.00	3,260
March	75.00	62.03	4,740
April	80.05	74.00	10,620
May	89.00	79.00	4,285
June	96.00	86.75	8,040
July	95.00	89.25	9,470
August	98.00	95.00	8,330
September	99.69	96.50	12,020
October (1-27) *	100.00	93.50	25,230
October (28-31)	99.50	99.00	590
November	99.50	97.00	11,420
December	101.00	99.25	16,000

* Prior to October 27, 2009, all trades were for Series 2A Debentures of the Fund.

Series 3 Debentures

APUC's Series 3 Debentures have been listed and posted for trading on the TSX since December 2, 2009 under the symbol "AQN.DB.B".

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

Period	Trading of Series 3 Debentures on the TSX		
	High	Low	Volume
	$	$	$100
December (2 – 31)	106.00	100.55	199,610

DIRECTORS, OFFICERS AND MANAGEMENT OF APUC

7.1 Name, Occupation and Security Holdings of APUC Directors and Officers/Managers

The following table sets forth certain information with respect to the directors and officers of APUC, and information on their history with APCo (previously the Fund). 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 Beneficially Owned (Dollar Value as of March 26, 2010[1])
CHRISTOPHER J. BALL Toronto, Ontario, Canada Age: 58	Mr. Ball is currently the Executive Vice President of Corpfinance International Limited, an investment banking boutique firm. 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 Director of the Independent Power Association of British Columbia.	Director of APUC since October 27, 2009. Trustee of the Fund/APCo since October 22, 2002	24,200[2] ($110,836)

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares Beneficially Owned (Dollar Value as of March 26, 2010[1])
KENNETH MOORE Toronto, Ontario, Canada Age: 51	Mr. Moore is currently 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., another 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 and 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).	Director of APUC since October 27, 2009. Trustee of the Fund/APCo since December 18, 1998	18,000 ($82,440)
GEORGE L. STEEVES Aurora, Ontario, Canada Age: 60	Mr. 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 Chairman, director and/or audit committee member of public and private companies, including the Fund, 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 Carlton University and holds the Professional Engineering designation in Ontario and British Columbia.	Director of APUC since October 27, 2009. Trustee of the Fund/APCo since September 8, 1997	17,241(3) ($78,964)

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares Beneficially Owned (Dollar Value as of March 26, 2010[1])
CHRISTOPHER HUSKILSON Wellington, Nova Scotia, Canada Age: 52	Mr. Huskilson is currently the President and Chief Executive Officer of Emera Inc, a North American energy and services company. Since 1980, Mr. Huskilson has held a number of positions within Nova Scotia Power Inc, and is currently a director of Emera, Nova Scotia Power Inc. and chairman of Bangor Hydro-Electric Company.	Director of APUC since October 27, 2009. Trustee of the Fund/APCo since July 27, 2009	Nil
DAVID BRONICHESKI Oakville, Ontario, Canada Age: 49	Mr.Bronicheski is the Chief Financial Officer of APUC, APCo and APT.	Officer of APUC since October 27, 2009. Officer of the Fund/APCo since September 17 2007[4] [5]	5,300 ($24,274)
CHRISTOPHER K. JARRATT[6][7] Oakville, Ontario, Canada Age: 51	Mr. Jarratt is currently acting as Vice Chairman of the Board of Directors of APUC and serves on the APUC Strategic Development Committee. Mr. Jarratt has been invited to join the Board of APUC and will be included on APUC's slate of proposed Directors at the next Annual General Meeting of Shareholders to be held on June, 2010.	N/A	111,378 ($510,111)
IAN E. ROBERTSON[6][7] Oakville, Ontario, Canada Age: 50	Mr. Robertson is currently the President and Chief Executive Officer of APUC and serves on the APUC Strategic Development Committee. Mr. Robertson has been invited to join the Board of APUC and will be included on APUC's slate of proposed Directors at the next Annual General Meeting of Shareholders to be held in June 2010.	N/A	127,663 ($584,697)
MARY LOU MCDONALD Ontario,Canada Age: 47	Ms. McDonald has been general counsel for APCo since April 2008 and was appointed Corporate Secretary of APUC on March 4, 2010. Prior to her position with APCo, she was in-house legal counsel for a division of Superior Plus LP. From 2000 to 2003, Ms. McDonald was an associate at the law firm of Macleod Dixon LLP in Calgary, Alberta.	Officer of APUC since March 4, 2010	1,500 ($6,870)

Notes:

(1) The closing price of shares on March 26, 2010 was $4.58.

(2) Mr. Ball directly owns 3,000 Common Shares and Cyntoria Financial Services Inc. (a private corporation owned by Mr. Ball and his spouse) owns 21,200 Common Shares. Mr. Ball exercises control and direction over the Common Shares owned by Cyntoria Financial Services Inc.
(3) 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.
(4) Mr. Bronicheski became an officer of the Fund on September 17, 2007.
(5) Prior to becoming an officer of APT and the Fund in September 2007, Mr. Bronicheski was the Chief Financial Officer of Amtelecom Income Fund from July 2003 to July 2007.
(6) Messrs. Jarratt and Robertson, together with others, collectively own all of the issued and outstanding shares of APMI.
(7) As consideration for payment of APUC's acquisition of APMI's interest in the management agreement, Mr. Robertson and Mr. Jarratt upon shareholder approval at the 2010 annual and special meeting will each receive an additional 289,687 Common Shares.

Each of the Directors will serve as a Director of APUC until the next annual meeting of shareholders or until his successor is elected in accordance with the by-laws of APUC (the "**By-Laws**"). Each of the Directors has held his principal occupation for more than five years. APUC does not have an executive committee of the Directors. However, each Director serves as a member of the APUC's Audit Committee and Corporate Governance Committee.

Approximately 338,268 of the Common Shares are beneficially owned, directly or indirectly, by the directors and senior officers of APMI, as a group. Directors and officers (including APMI) hold, in the aggregate, 397,709 Common Shares as of March 31, 2010.

7.2 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 all four Directors of APUC, Christopher Ball (Chairman), Kenneth Moore, George Steeves and Christopher Huskilson, all of whom are independent and financially literate for purposes of NI 52-110. 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.

Audit Committee Charter

Attached as Schedule D to the AIF is the charter for APUC's audit committee (the " **Audit Committee**").

Relevant Education and Experience

The following is a description of the education and experience, apart from their roles as Directors of the Fund, 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 also has extensive financial experience. He 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 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 the Fund, Borealis Hydroelectric Holdings Inc. and KMS. 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 Carlton University and holds the Professional Engineering designation in Ontario and British Columbia.

Mr. Huskilson holds a Bachelor of Science in Engineering and a Master of Science in Engineering from the University of New Brunswick. Mr. Huskilson is currently the President and Chief Executive Officer of Emera Inc, a North American energy and services company. Since 1980, Mr. Huskilson has held a number of positions within Nova Scotia Power Inc, and is currently a director of Emera, Nova Scotia Power Inc. and chairman of Bangor Hydro-Electric Company

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, 2009 and December 31, 2008, KPMG LLP charged the following fees to APUC:

Services	2009 Fees ($)	2008 Fees ($)
Audit Fees	580,000	547,000
Audit-Related Fees(1)	862,000	88,000
Tax Fees(2)	1,156,000	563,754
All Other Fees	Nil	Nil

Notes:

(1) For assurance and related services that are reasonably related to the performance of the audit or review of the Fund's financial statements and not reported under Audit Fees, including services in connection with prospectus and securities filings, accounting advice, French translation services and financial statement audits of subsidiary companies.
(2) For tax compliance, advice and planning services.

7.3 Corporate Governance Committee

The Directors have also established a Corporate Governance Committee comprised of all four Directors of APUC, all of whom are independent Directors. This Committee also serves as the Director nominating and evaluating committee and the compensation committee of APUC. The Corporate Governance Committee is responsible for reviewing APUC's corporate governance practices and Director compensation. The Corporate Governance Committee will also consider from time to time the effectiveness of the Directors and whether an increase to the number of Directors is warranted.

The Corporate Governance Committee is also responsible for reviewing Directors compensation on an annual basis, or more frequently if required, in light of the risks involved in being an effective Director. In addition, the Corporate Governance Committee will make recommendations to the Directors regarding the compensation of executive officers of APUC and produce a report concerning executive compensation in compliance with Canadian securities law requirements.

7.4 Potential Material Conflicts of Interest

Other than as disclosed in this AIF and APUC's financial statements and management's discussion and analysis for the fiscal year ended December 31, 2009, APUC is not aware of any instance in which the interest of any current or proposed director or officer in a contract or transaction conflicts with the interest of APUC. APUC is not aware of any interest of such persons in a material contract or material transaction.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

8.1 Legal Proceedings

Except as disclosed elsewhere in this AIF, the only legal proceedings involving APUC or its subsidiaries that were material in 2009 are as follows:

Trafalgar Class B Note

As reported in previous public filings of the Fund, Trafalgar Power, Inc. and Christine Falls Power Corporation (collectively, " **Trafalgar**") commenced an action in 1999 in U.S. District Court against the Fund, APMI and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to the Fund and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in Trafalgar entities that own hydroelectric generating facilities in New York. In 2001, Trafalgar and other entities also filed for Chapter 11 reorganization in bankruptcy court and also filed a multi-count adversary complaint against certain APCo entities, which complaint was then transferred to the District Court. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the Trafalgar Class B Note, that the Fund was therefore the holder and owner of the Trafalgar Class B Note, and that all other claims by Trafalgar with respect to the transfer of the Trafalgar Class B Note were without merit. Further, on November 6, 2008, the claims that were remaining in the District Court were dismissed by summary judgement. On October 22, 2009 Trafalgar filed an appeal from the November 6, 2008 summary judgement to the United States Court of Appeals for the Second Circuit. Financial loss to the Fund is not expected to result from the appeal.

Côte Ste-Catherine Water Lease Dues

On December 19, 1996, the Attorney General of Québec ("**Québec AG**") filed suit in Québec Superior Court against Algonquin Développement Côte Ste-Catherine Inc. (Développement Hydromega), a predecessor company to a Fund subsidiary. The Québec AG at trial claimed $5.4 million for amounts that the Fund entities have been paying to the federal authority under its water lease with the authority. The Fund entities brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009. The Côte Ste-Catherine Facility currently pays water lease dues to the federal government, but if the Québec AG is successful in any appeal, an adjustment and/or increase of such amounts is possible.

8.2 REGULATORY ACTIONS

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2009, 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.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

9.1 Management's Interest

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, 2009, 2008 and 2007, 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 the Fund.

TRANSFER AGENTS AND REGISTRARS

10.1 CIBC Mellon

The transfer agent and registrar for the Trust Units is CIBC Mellon Trust Company, at its offices in Toronto, Montréal, Vancouver, Calgary, Halifax and Winnipeg.

MATERIAL CONTRACTS

Listing of 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 2009 (or prior to 2009 in the case of contracts that are still in effect) that are material to APUC.

(a) Management Agreement

Prior to December 21, 2009, the Fund was managed by pursuant to the terms of the amended and restated management agreement dated as of January 1, 2006, as amended, between APMI and the Fund (the **"Management Agreement"**). On December 21, 2009, APUC acquired the interest previously held by APMI in the Management Agreement. See "*Developments in Fiscal 2009*" for more details.

APMI is owned by the shareholders of APC, and the principals of APMI together have over 50 years experience and extensive contacts in the independent power industry in Canada and the US. APMI provided management services to the Fund (including advice and consultation concerning business planning, support, guidance and policy making) pursuant to the Management Agreement.

(b) Operations Supervisory, Administration, Governance and Direct Operations Agreements

As a result of the Fund being managed under the Management Agreement, the Fund entered into a number of ancillary agreements with APMI and entities controlled by APMI in order to administer the business and general operations of the Fund. These agreements included the Operations Supervisory Agreement, the Administration Agreement, the Governance Agreement and the Direct Operations Agreements. As a result of the internalization of management note above, these activities are being performed by APUC.

(c) **Trust Indenture** (in respect of the Series 1A Debenture and Series 2A Debentures) (See "General Description of Capital Structure – Convertible Debentures").

(d) **Series 3 Trust Indenture** (in respect of the Series 3 Debentures) (See "*General Description of Capital Structure – Convertible Debentures*").

INTERESTS OF EXPERTS

13.1 Interests of Experts

KPMG LLP are APUC's external auditors and have reported to the shareholders on APUC's consolidated financial statements for the year ended December 31, 2009 in their report dated March 23, 2010. In connection with their audit, KPMG LLP has confirmed that they are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario.

ADDITIONAL INFORMATION

14.1 Sources for Additional Information

Additional financial information is provided in APUC's financial statements and management discussion and analysis for the year ended December 31, 2009. A copy of such documents may be obtained upon request from APUC and are also available for review on SEDAR at www.sedar.com.

APUC will also provide to any person upon request to APUC:

(a) when shares are in the course of a distribution pursuant to a short form prospectus or when a preliminary short form prospectus has been filed in respect of a distribution of shares,

  (i) one copy of APUC's Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

  (ii) one copy of the comparative financial statements of APUC for its most recently completed financial year together with the accompanying report of the auditors and one copy of any interim financial statements of APUC subsequent to the financial statements for its most recently completed financial year;

  (iii) one copy of APUC's information circular in respect of its most recent annual meeting of shareholders that involved the election of Directors or one copy of any annual filing prepared in lieu of that information circular, as appropriate; and

  (iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or

(b) at any other time, one copy of any other documents referred to in (a)(i), (ii) and (iii) above, provided APUC may require the payment of a reasonable charge if the request is made by a person who is not a shareholder.

SCHEDULE A

Renewable Energy - Hydroelectric and Wind Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Ontario Facilities						
Facility: Long Sault Rapids Facility (Hydroelectric) **Owner:** Algonquin Power (Long Sault) Partnership and N-R Power Partnership	16,000	Abitibi River near Cochrane, Ontario	**Electricity Purchaser:** OEFC **Rates:** Summer Energy $0.04561kW Summer Capacity $0.07045/kW-hr Winter Energy $0.05595/kW-hr Winter Capacity $0.09304/kW-hr	119,500	2047	2048
Facility: Hurdman Dam Facility (Hydroelectric) **Owner:** APFC	570	Mattawa River near Mattawa, Ontario	**Electricity Purchaser:** Hydro One Inc. **Rates:** Paid on Hourly Spot Market Price – blended rate of approximately	4,500	2015	2015
Facility: Burgess Dam Facility (Hydroelectric) **Owner:** APFC	140	Muskoka River near Bala, Ontario	**Electricity Purchaser:** OEFC **Rates:** Winter Peak $0.0809 /kW-hr Winter Off-Peak $0.0319 /kW-hr Summer Peak $0.0752 /kW-hr Summer Off-Peak $0.0228 kW-hr	950	2010	Month to Month Lease [2]

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Facility: Campbellford Facility (Hydroelectric) **Owner:** Campbellford LP	4,000	Trent River near Campbellford, Ontario	**Electricity Purchaser:** OEFC **Rates:** Winter On-Peak $0.0961/kW -hr Winter Off-Peak $0.0373/kW-hr Summer On-Peak $0.0797/kW-hr Summer Off-Peak $0.0326/kW-hr	27,850	2019	2019
Québec Developments						
Facility: Saint-Alban Facility (Hydroelectric) **Owner:** SLI[4]	8,200	Ste-Anne River near the Village of Saint-Alban, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** $0.07387/kW-hr (Jan – Nov) $0.07609/kW-hr (Dec)	37,250	2016	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:** $0.07387/kW-hr (Jan-Nov) $0.07609/kW-hr (Dec)	23,750	2020	Owned
Facility: Rawdon Facility (Hydroelectric) **Owner:** APFC	2,500	Ouareau River near the Village of Rawdon, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** $/kW-hr $0.07387/kW-hr (Jan-Nov) $0.07609/kW-hr (Dec)	13,900	2014	2014

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
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 $0.048/kW-hr Phase II Energy $0.06302/kW-hr Capacity 154.68/kilowatt (over the average kilowatt output over the period December to March) Phase III Energy $0.06562/kW-hr Capacity $162.18/kilowatt (over the average kilowatt output over the period December to March)	Phase 1: 15,500 Phase II: 35,000 Phase III: 34,750	Phase 1: 2021 Phase II: 2018 Phase III: 2021	2030
Facility: Ste-Raphaël Facility (Hydroelectric) **Owner:** APFC	3,500	Rivière de Sud near Québec City, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** $0.07387/kW-hr (Jan-Nov) $0.07609/kW-hr (Dec)	22,000	2014	2013
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:** $0.05700/kW-hr	21,000	2027	2023

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
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:** $0.07387/kW-hr (Jan-Nov) $0.07609/kW/hr (Dec)	17,100	2015	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 $0.06213/kW-hr Winter Energy $0.11392/kW-hr	9,850	2014	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:** $0.07387/kW-hr (Jan-Nov) $0.07609/kW-hr (Dec)	12,000	2014	Owned
Facility: Belleterre Facility (Hydroelectric) **Owner:** APFC	2,200	Winneway River in the Municipality of Laforce, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** Summer Energy: $0.06157/kW-hr Winter Energy: $0.11398/kW-hr Capacity: $152.18/kilowatt (over the average kilowatt output over the period December to March)	11,250	2013	2011

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Facility: Donnacona Facility (Hydroelectric) **Owner:** Donnacona Partnership	4,800	Jacques Cartier River near Donnacona, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** $0.07387/kW-hr (Jan-Nov) $0.07609/kW-hr (Dec)	20,300	2022	2017
Facility: St. Raphaël de Bellechasse Facility (Arthurville) (Hydroelectric) **Owner:** APT	650	Riviere du Sud downstream from Ste-Raphaël	**Electricity Purchaser:** Hydro-Québec **Rates:** $0.07387/kW-hr (Jan-Nov) $0.07609/kW-hr (Dec)	2,800	2013	Owned
Newfoundland Facility						
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	17,500	2024	2048
New York Facilities						
Facility: Ogdensburg Facility (Hydroelectric) **Owner:** Trafalgar[5]	3,675	Oswegatchie River near Ogdensburg, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04486/kW-hr (est)[6]	11,100	2011	2038
Facility: Forestport Facility (Hydroelectric) **Owner:** Trafalgar[5]	3,300	Black River near Boonville, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04436/kW-hr (est)[6]	11,500	2011	Owned

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Facility: Herkimer Facility (Hydroelectric) **Owner:** Trafalgar[5]	1,680	West Canada Creek near Herkimer, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04436/kW-hr[6]	0[7]	2011	Owned
Facility: Christine Falls Facility (Hydroelectric) **Owner:** Christine Falls Corporation[5]	850	Sacandaga River near Clifton, New York	**Electricity Purchaser:** National Grid **Rates:** US $0.05107/kW-hr (est)[6]	3,300	2028	Owned
Facility: Cranberry Lake (Hydroelectric) **Owner:** Trafalgar[5]	500	Oswegatchie River near Clifton, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04498/kW-hr (est)[6]	1,800	2011	2035
Facility: Kayuta Lake Facility (Hydroelectric) **Owner:** Trafalgar[5]	400	Black River near Boonville, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.015/kW-hr (est)	1,800	2028	Owned
Facility: Adams Facility (Hydroelectric) **Owner:** Trafalgar [5]	350	Sandy Creek near Adams, New York	**Electricity Purchaser:** National Grid **Rates:** US$ 0.00852/kW-hr (est)	0[7]	2028	Owned

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Facility: Kings Falls Facility (Hydroelectric) **Owner:** Tug Hill Energy, Inc.[8]	1,750	Deer River near Copenhagen, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04463/kW-hr[6]	3,400	2011	Owned
Facility: Otter Creek Facility (Hydroelectric) **Owner:** Tug Hill Energy, Inc.[8]	530	Otter Creek in Craig, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04448/kW-hr (est)[6]	1,900	2011	Owned
Facility: Phoenix Facility (Hydroelectric) **Owner:** Oswego Hydro Partners L.P.[8]	3,500	Oswego River in Phoenix, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.09205/kW-hr Flat Rate	11,300	2026	Owned
Facility: Beaver Falls Facility (Hydroelectric) **Owner:** Algonquin Power (Beaver Falls) LLC	2,500	Beaver River in Beaver Falls, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04036/kW-hr (est)	15,400	2019	2008
Facility: Burt Dam Facility (Hydroelectric) **Owner:** Burt Dam Partnership	600	18 Mile Creek near Newfane, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.0450/kW-hr (est)[6]	2,000	2011	2036

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Facility: Hollow Dam Facility (Hydroelectric) **Owner:** Hollow Dam Partnership	900	Oswegatchie River near Gouverneur, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04452/kW-hr (est)[6]	4,400	2011	2026
New England Facilities						
Facility: Greggs Falls Facility (Hydroelectric) **Owner:** Greggs Falls Partnership	3,500	Piscataquog River near the Town of Goffstown, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US$0.06478/kW-hr (est)[8]	10,500	60 day written notice	2031
Facility: Pembroke Facility (Hydroelectric) **Owner:** Pembroke Hydro Associates Limited Partnership[10]	2,600	Suncook River near the Town of Pembroke, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US$0.06132/kW-hr (est)[8]	9,800	60 day written notice	Owned
Facility: Clement Facility (Hydroelectric) **Owner:** Clement Dam Hydroelectric LLC [11]	2,400	Winnipisauhee River near the Town of Tilton, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US$0.06581/kW-hr (est)[8]	10,700	60 day written notice	2032

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Facility: Franklin Facility (Hydroelectric) **Owner:** Franklin Power LLC[8]	River Bend 1,600 Steven's Mill 200	Winnipesaukee River near the Town of Franklin, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** River Bend US$0.06748/kW-hr (est)[8] Steven's Mill US$0.06770/kW-hr (est)[8]	River Bend 6,800 Steven's Mill 1,000	60 day written notice – both sites	Owned
Facility: Lochmere Facility (Hydroelectric) **Owner:** HDI Partnership	1,200	Winnipesaukee River near Lochmere, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US$0.06717/kW-hr (est)[8]	4,200	60 day written notice	2033
Facility: Lakeport Facility (Hydroelectric) **Owner:** Lakeport Corporation	600	Winnipesaukee River near Laconia, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US$0.06821/kW-hr (est)[8]	2,500	60 day written notice	2032
Facility: Milton Facility (Hydroelectric) **Owner:** SFR Hydro Corporation	1,335	Salmon River near the Town of Milton, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US$0.06493/kW-hr (est)[8]	6,400	60 day written notice	Owned
Facility: Mine Falls Facility (Hydroelectric) **Owner:** Mine Falls Limited Partnership	3,000	Nashua River near the City of Nashua, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US $0.06369/kW-hr (est)[8]	11,400	60 day written notice	2024

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Facility: Great Falls Facility (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 $0.05998/kW-hr (est)[8]	23,326	60 day written notice	2021
Facility: Moretown Facility (Hydroelectric) **Owner:** Moretown Partnership	1,200	Mad River near Moretown, Vermont	**Electricity Purchaser:** Vermont Power Exchange, Inc. **Rates:** Winter On-Peak US$0.1078/kW-hr Winter Off-Peak US$0.0682/kW-hr Summer On-Peak US$0.0978/kW-hr Summer Off-Peak US$0.0539/kW-hr Capacity Adder US$0.0243/kW-hr	2,100	2018	Owned
Western Canada Facility						
Facility: Dickson Dam Facility (Hydroelectric) **Owner:** APOT	15,000	Innisfail, Alberta	**Electricity Purchaser:** TransAlta Utilities Corporation **Rates:** Energy: $0.0619/kW-hr	67,250	2012	2030

Maritime Region

Facility: Tinker Facility (Hydroelectric) **Owner:** **APT**	33,500	Perth-Andover, New Brunswick	**Electricity Purchaser:** Northern Maine Gen Co. Town of Perth-Andover **Rates:** Northern Maine Gen Co.: US $0.071/kWhr (net of transmission charges – variable monthly) Town of Perth Andover: $.065/kWhr CDN (net of transmission charges – variable monthly)	133,200	2011	Owned
Facility: Caribou Facility (Hydroelectric) **Owner:** Northern Maine Gen Co.	900	Caribou, Maine	**Electricity Purchaser:** AES **Rates:** Energy - US $0.050/kWhr	4,200	2011	Owned
Facility: Squa Pan Facilty (Hydroelectric) **Owner:** Northern Maine Gen Co.	1,400	Squa Pan Lake, near Caribou Maine	**Electricity Purchaser:** AES **Rates:** Energy - US $0.050/kWhr Reserve Market: variable monthly US $0.3/kW-hr (average estimate)	700	2011	Owned

Wind Facility

Facility: St. Leon Facility (Wind) **Owner:** St. Leon LP	99,000	St. Leon, Manitoba	**Electricity Purchaser:** Manitoba Hydro **Rates:** Dependable $0.05961/kW-hr (average estimate) Non-dependable $0.04762/kW-hr (average estimate) Rates indexed annually to CPI in May. Wind Power Production Incentive $ 0.0100/kW-hr	372,000	2025 + one 5 year extension	2043

Notes:

(1) 2010 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) No agreement has been obtained for a long-term lease; the current lease is on a month-to-month basis.

(4) See "*General Description of the Businesses of the Divisions of APUC: Production Method, Principal Markets, Distribution Methods and Material Facilities – Hydroelectric – Material Facilities – Saint-Alban Facility*"

(5) APC provides Trafalgar with certain operational services in respect of the Trafalgar Facilities.

(6) These rates reflect the estimated Avoided Costs of National Grid.

(7) Offline for repairs in 2009. No decision has been made as to the timing of repairing these Facilities.

(8) PSNH purchases the energy produced by these generating stations at the ISO-NE. market rates. These agreements are cancellable on 60 days written notice.

SCHEDULE B

Thermal - Biomass, Cogeneration, Landfill Gas, Steam, Diesel and Energy From Waste Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	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: $0.0709/kW-hr	74,000[2]	2014	Owned
Thermal - Cogeneration Facilities						
Facility: Sanger Facility (Cogeneration) **Owner:** Sanger LLC[1]	56,000	Sanger, California	**Electricity Purchaser:** PG&E **Rates:** Period A PG&E Avoided Cost US$ 0.054/ kW-hr (estimated average)* Period B US$ 0.049/ kW-hr (estimated average)* * subject to gas price indexing **Capacity Payment** US$ 190 per kW/year up to 38,000 kW-hrs + bonus of 18% (80% earned May – Oct)	133,000	2021	Owned

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Facility: Windsor Locks Facility (Cogeneration) **Owner:** Algonquin Windsor Locks LLC[1]	56,000	Windsor Locks, Connecticut	**Electricity Purchaser:** Connecticut Light and Power Company **Rates:** Market Rates after April 13, included hourly energy, forward capacity and forward reserve payments Mill/NGC US$0.043/kW-hr* Capacity $186,000** Steam - DNM/NGC US$6.43/1000lbs* Capacity $117,** * Estimated average rate, includes variable component based on natural gas prices. April 10, 2010 – Forward Reserve Market, Capacity Market and Spot Market – market prices	182,000	2010	2018
Facility: Brampton Cogeneration Inc. (Cogeneration) **Owner:** APOT	N/A	Brampton, Ontario	**Electricity Purchaser:** N/A **Rates:** **Steam - Normapac** $7.13/1000lbs* Capacity $102,000** * Estimated average rate, includes variable component based on natural gas prices. **Estimated average monthly rate, charges are partially CPI indexed.	675 million lbs of steam	2024	N/A

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Facility: Crossroads Facility (Cogeneration) **Owner:** KMS Crossroads, Inc.	10,000	Mahwah, New Jersey	**Electricity Purchaser:** N/A **Rates:** N/A	N/A	N/A	N/A
Thermal - Landfill Gas Facilities						
Facility: Bordeaux (Landfill Gas) **Owner:** MM Nashville Energy LLC	1,900	Nashville, Tennessee	**Electricity Purchaser:** N/A **Rates:** N/A	0[2]	N/A	Month to month
Facility: Balefill (Landfill Gas) **Owner:** MM Hackensack Energy LLC	3,800	Kearney, New Jersey	**Electricity Purchaser:** N/A **Rates:** N/A	0[2]	N/A	2017
Facility: Kingsland (Landfill Gas) **Owner:** MM Hackensack Energy LLC	2,900	North Arlington, New Jersey	**Electricity Purchaser:** N/A **Rates:** N/A	0[2]	N/A	2017
Facility: Meadowlands Gas Treater (Landfill Gas) **Owner:** Algonquin-Cambrian	n/a	Kearney, New Jersey	**Electricity Purchaser:** N/A **Rates:** N/A	0[2]	N/A	N/A

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	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:** $0.055/kW-hr (average estimated summer rate) $0.0641/kW-hr (average estimated winter rate) Tipping - - Peel – $92/tonne up to 127,900 tonnes, $67 tonnes thereafter Waste rates subject to monthly CPI indexing	7,500	2012	Owned
Thermal - Diesel						
Facility: Tinker Facility (Diesel) **Owner:** Tinker Gen Co.	1,000	Perth-Andover, New Brunswick	**Electricity Purchaser:** Northern Maine Gen Co. **Rates:** Capacity – US $2.875/kw -mo	0[3]	2011	Owned
Facility: Caribou Facility (Diesel) **Owner:** Northern Maine Gen Co.	7,000	Caribou, Maine	**Electricity Purchaser: AES** **Rates:** US$ 0.050/ kW-hr (non-dispatch) Reserve Market: variable monthly US $0.30/kW-hr (average estimate) Capacity – US $2.875/kw -mo	0[3]	2011	Owned

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2010 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Facility: Flo's Inn Facility (Diesel) **Owner:** Northern Maine Gen Co.	4,000	Caribou, Maine	**Electricity Purchaser:** AES **Rates:** US$ 0.050/ kW-hr (non-dispatch) Reserve Market: variable monthly US $0.30/kW-hr (average estimate) Capacity – US $2.875/kw -mo	0[3]	2011	Owned
Facility: Loring Facility (Diesel) **Owner:** Northern Maine Gen Co.	3,000	Caribou, Maine	**Electricity Purchaser:** AES **Rates:** US$ 0.050/ kW-hr (non-dispatch) Reserve Market: variable monthly US $0.30/kW-hr (average estimate) Capacity – US $2.956/kw -mo	0[3]	2011	Owned
Steam						
Facility: Caribou Facility (Steam) **Owner:** Northern Maine Gen Co.	21,700	Caribou, Maine	**Electricity Purchaser:** AES **Rates:** US$ 0.050/ kW-hr (non-dispatch) Reserve Market: variable monthly US $0.30/kW-hr (average estimate) Capacity – US $2.956/kw -mo	0[3]	2011	Owned

Notes:

(1) This entity is a subsidiary of APFA.
(2) These facilities no longer fit APUC's preferred asset profile and are no longer considered strategic to APUC. As a result, APUC's interest in these facilities are expected to be sold in early 2010.
(3) Available to provide capacity only

SCHEDULE C

Wastewater and Water Distribution Facilities

Utility	Owner[1]	Location	Type of Utility	December 31, 2009 Connections	Rates
Black Mountain	Black Mountain Sewer Corporation	Carefree, Arizona	Wastewater	2,138	Residential US $45.64 (standard monthly rate)
Gold Canyon	Gold Canyon Sewer Company	Gold Canyon Arizona	Wastewater	7,312	Residential US $52.40 (standard monthly rate)
Bella Vista	Bella Vista Water Co., Inc.	Sierra Vista, Arizona	Water Distribution	8,797	Residential US $26.75 (Average monthly rate)
Tall Timbers [2]	Tall Timbers Utility Company, Inc.	Tyler, Texas	Wastewater	1,352	Residential US $56.18 (standard monthly rate)
Woodmark	Woodmark Utilities, Inc.	Tyler, Texas	Wastewater	1,567	Residential US $47.76 (standard monthly rate)
Litchfield Park	Litchfield Park Service Company	Litchfield, Park, Arizona	Wastewater	18,289	Residential US $27.20 Commercial
			Water Distribution	16,266	US $46.00 US $24.28 (Average residential rate)
Fox River	AWRI	Sheridan, Illinois	Wastewater	219	US $240.08
			Water Distribution	220	US $141.61
Timber Creek	AWRM	DeSoto, Missouri	Wastewater	22	US $16.00 min & $17.24/1000 gal.
			Water Distribution	31	US $8.96 min. & US $5.96/1000 gal
Holliday Hills	AWRM	Branson, Missouri	Water Distribution	477	US $8.96 min. & US $5.96/1000 gal

Utility	Owner[1]	Location	Type of Utility	December 31, 2009 Connections	Rates
Ozark Mountain	AWRM	Kimberling City, Missouri	Wastewater	241	US $16.00 min & $17.24/1000 gal.
			Water Distribution	253	US $8.96 min. & $5.96/1000 gal
Holly Lake Ranch [2]	AWRT	Hawkins, Texas	Wastewater	130	US $128.53 min & US $3.65/1000 gal.
			Water Distribution	1,884	US $39.81 min. & $1.30/1000 gal
Big Eddy [2]	AWRT	Flint, Texas	Wastewater	394	US $128.53 min & US $3.65/1000 gal.
			Water Distribution	660	US $39.81 min. & $1.30/1000 gal
Piney Shores [2]	AWRT	Conroe, Texas	Wastewater	181	US $128.53 min & US $3.65/1000 gal.
			Water Distribution	185	US $39.81 min. & $1.30/1000 gal
Hill Country [2]	AWRT	New Braunfels, Texas	Wastewater	373	US $128.53 min & US $3.65/1000 gal.
			Water Distribution	236	US $39.81 min. & $1.30/1000 gal
Rio Rico	Rio Rico Utilities Inc.	Rio Rico, Arizona	Wastewater	2,193	US $56.36 (residential rates)
			Water Distribution	6,696	US $6.45 min. & 0-4,000 gal – US $1.44/1,000 gal 4,001-10,000 gal – US $1.70/1,000 gal >10,000 gal – US $1.90/1,000 gal
Northern Sunrise	Northern Sunrise Water Company Inc.	Sierra Vista, Arizona	Water Distribution	357	US $31.00 min & 0-5,000 gal – US $2.00/1,000 gal 5,001-10,000 gal – US $2.75/1,000 gal >10,000 gal – US $3.90/1,000 gal
Southern Sunrise	Southern Sunrise Water Company Inc.	Sierra Vista, Arizona	Water Distribution	857	US $31.00 min & 0-5,000 gal – US $2.00/1,000 gal 5,001-10,000 gal – US $2.75/1,000 gal >10,000 gal – US $3.90/1,000 gal

Utility	Owner[1]	Location	Type of Utility	December 31, 2009 Connections	Rates
Entrada Del Oro [3]	Entrada Del Oro Sewer Company	Gold Canyon, Arizona	Wastewater	240	US $76.00 (standard monthly rate)
Seaside Resort	AWRT	Galveston, Texas	Water Distribution Wastewater Collection	144 144	Rates are established in accordance with rate making principles in the state of Texas that provides an after tax return of 12% on investment [4]
Total connections				**71,648**	

Notes:

(1) Each of these entities is a wholly-owned subsidiary of Liberty Water Co.
(2) Existing approved rates and tariffs. These five Texas utilities initiated rate cases in early 2009, with a test year ended December 31, 2008. These rates are in effect on an interim basis, pending final approval from the TCEO. At present, the rates have been contested and are subject to an evidentiary hearing.
(3) Liberty Water Co. currently holds a beneficial interest in the shares of the company pending regulatory approval of its acquisition.
(4) It is expected that the rates will result in EBITDA of approximately $419,000 per year

SCHEDULE D

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 ("N**I 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.

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 therefor 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 therefor) 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 Section 5741 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.

SCHEDULE E

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”. 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.

Exhibit 99.2

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AUDITORS' REPORT

To the Board of Directors of Algonquin Power & Utilities Corp. (formerly Algonquin Power Income Fund):

We have audited the consolidated balance sheets of Algonquin Power & Utilities Corp. (the "Company") as at December 31, 2009 and 2008 and the consolidated statements of operations, cash flows, deficit, comprehensive income/(loss) and accumulated other comprehensive income/(loss), for each of the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. With respect to the consolidated financial statements for the year ended December 31, 2009, we also 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 an audit to obtain reasonable assurance 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.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and 2008 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 23, 2010

KPMG LLP, is a Canadian limited liability partnership and a member firm of the KPMG Network of independent member firms affiliated with KPMG International, a Swiss cooperative. KPMG Canada provides services to KPMG LLP.

Consolidated Financial Statements of

Algonquin Power & Utilities Corp.

For the year ended December 31, 2009 and December 31, 2008

Algonquin Power & Utilities Corp
Consolidated Balance Sheets
(thousands of Canadian dollars)

	2009	2008 Restated see note 2(b))
ASSETS		
Current assets:		
Cash	$ 2,796	$ 5,902
Short term investments (note 1(c))	40,010	—
Accounts receivable	20,484	26,600
Prepaid expenses	4,674	2,832
Income tax receivable	1,143	1,538
Current portion of future tax asset	14,566	—
Current portion of notes receivable	521	485
	84,194	37,357
Long-term investments and notes receivable (note 6)	24,029	27,954
Future non-current income tax asset (note 14)	61,219	2,894
Property, plant and equipment (notes 2(b) and 7)	749,350	805,350
Intangible assets (note 8)	85,929	97,398
Restricted cash	4,316	5,295
Deferred financing costs	200	243
Other assets (notes 2(b), 4(a) and 5)	4,176	2,024
	$1,013,413	$ 978,515
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 33,219	$ 34,074
Distributions / dividends payable	1,857	1,587
Current portion of long-term liabilities (note 10)	3,360	3,235
Current portion of other long-term liabilities (note 12)	1,025	1,001
Current portion of derivative liabilities (note 9)	5,775	8,438
Current income tax liability	5	541
Current portion of deferred credits	10,500	—
Future income tax liability (note 14)	913	1,191
	56,654	50,067
Long-term liabilities (notes 10)	241,412	293,590
Convertible debentures (note 11)	173,257	140,427
Other long-term liabilities (note 12)	25,228	28,859
Future non-current income tax liability (note 14)	79,914	85,804
Derivative liabilities (note 9)	3,920	25,116
Deferred credits (note 3)	39,379	—
Non controlling interest (note 13)	—	12,548
Shareholders' equity:		
Shareholders' capital (notes 3 and 13)	787,037	722,215
Deficit	(344,676)	(358,669)
Accumulated other comprehensive loss	(48,712)	(21,442)
	393,649	342,104
Commitments and contigencies (note 18)		
	$1,013,413	$ 978,515

See accompanying notes to consolidated financial statements

Approved by the Board of Directors

Director

Director

Algonquin Power & Utilities Corp
Consolidated Statements of Operations
(thousands of Canadian dollars, except per unit amounts)

	2009	2008
Revenue:		
Energy sales	$130,436	$158,508
Waste disposal fees	14,468	15,706
Water reclamation and distribution	38,513	35,233
Other revenue (note 24)	3,848	4,349
	187,265	213,796
Expenses		
Operating	102,736	120,479
Amortization of property, plant and equipment	38,578	36,541
Amortization of intangible assets	7,305	7,305
Management costs (note 17)	850	893
Administrative expenses	10,712	9,419
(Gain) / loss on foreign exchange	(1,261)	4,018
	158,920	178,655
Earnings before undernoted	28,345	35,141
Interest expense	21,387	26,288
Interest, dividend income and other income (note 23)	(6,401)	(7,023)
Write down of property, plant and equipment (note 7)	5,354	—
Write down of note receivable (note 6)	1,103	—
(Gain) / loss on derivative financial instruments (note 15)	(17,318)	37,748
	4,125	57,013
Earnings from operations before income taxes, non-controlling interest and corporatization costs	24,220	(21,872)
Management internalization costs (note 16)	4,693	—
Other corporatization costs (note 3)	3,460	—
Earnings/(loss) before income taxes and non-controlling interest	16,067	(21,872)
Income tax expense (recovery) (note 14)		
Current	397	(184)
Future	(18,324)	492
	(17,927)	308
Non-controlling interest in earnings (loss) of subsidaries	2,737	(3,142)
Net earnings / (loss)	$ 31,257	$ (19,038)
Basic net earnings / (loss) per share (note 22)	$ 0.39	$ (0.25)
Diluted net earnings / (loss) per share (note 22)	$ 0.39	$ (0.25)

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp
Consolidated Statements of Cash Flows
(thousands of Canadian dollars)

	2009	2008
Cash provided by (used in):		
Operating Activities:		
Net earnings / (loss)	$ 31,257	$(19,038)
Items not affecting cash:		
Amortization of property, plant and equipment	38,578	36,541
Amortization of intangible assets	7,305	7,305
Other amortization	1,441	1,130
Distributions received in excess of equity income	1,991	680
Future income taxes / (recovery)	(18,324)	492
Gain on sale of land	(1,451)	—
Gain on sale of note receivable and other assets	—	(918)
Write down of property, plant and equipment	5,354	—
Write down of note receivable	1,103	—
Inducement expense on convertible debenture conversion	1,252	—
Management internalization costs	4,693	—
Unrealized (gain) / loss on derivative financial instruments	(23,106)	42,426
Minority interest	2,737	(3,142)
Unrealized foreign exchange (gain) / loss	(1,503)	6,018
	51,327	71,494
Changes in non-cash operating working capital (note 21)	(1,305)	5,729
	50,022	77,223
Financing Activities:		
Cash distributions / dividends (note 20)	(19,043)	(66,108)
Cash distributions to non-controlling interest (notes 17 and 20)	(809)	(1,996)
Common share issue, net of costs	21,180	—
Convertible debenture issue, net of costs	57,975	—
Repayment / (advance) Trustee loans	218	(218)
Deferred financing costs	(109)	(463)
Increase in long-term liabilities	23,000	64,300
Decrease in long-term liabilities	(69,175)	(55,873)
Increase / (decrease) in other long-term liabilities	(5,870)	5,314
	7,367	(55,044)
Investing Activities:		
Decrease in restricted cash	343	1,787
Increase in short-term investments	(39,995)	—
Decrease/ (increase) in other assets	(2,774)	637
Receipt of principal on notes receivable	448	517
Increase in long-term investments (note 4(b))	(87)	(191)
Proceeds from liquidation of Highground assets (Note 4(c))	983	—
Proceeds from sale of land	2,502	—
Proceeds from sale on note receivable	—	2,954
Net additions to property, plant and equipment	(10,916)	(45,561)
Acquisition of Highground	—	20,617
The unit exchange transaction (note 3)	(10,813)	—
Acquisitions of operating entities	—	(8,274)
	(60,309)	(27,514)
Effect of exchange rate differences on cash	(186)	876
Increase / (decrease) in cash	(3,106)	(4,459)
Cash, beginning of the period	5,902	10,361
Cash, end of the period	$ 2,796	$ 5,902
	—	—
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest expense	$ 19,956	$ 26,160
Cash paid / (received) during the period for income taxes	$ 873	$ 1,336

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp
Consolidated Statement of Deficit
(thousands of Canadian dollars)

	2009	2008 Restated (see note 2(b))
Balance, beginning of period, as orginally reported	$(358,669)	$ (284,463)
Changes in accounting policies (note 2(b)	—	878
Adjustments relating to adoption of EIC 173 without restatement of prior periods (note 2(c))	2,048	—
Balance, beginning of period as restated	(356,621)	(283,585)
Net earnings	31,257	(19,038)
Distributions / dividends	(19,312)	(56,046)
Balance, end of period	$(344,676)	$ (358,669)

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp
Consolidated Statements of Comprehensive Income / (Loss) and
Accumulated Other Comprehensive Income / (Loss)
(thousands of Canadian dollars)

	2009	2008
Net earnings / (loss)	$ 31,257	$(19,038)
Other comprehensive income /(loss):		
Forward exchange contracts settled in the period (note 1(o))	(1,789)	(3,173)
Translation of self sustaining foreign operations (note 1(l))	(25,481)	25,621
Other comprehensive income / (loss)	(27,270)	22,448
Total comprehensive income / (loss)	$ 3,987	$ 3,410
Accumulated other comprehensive loss:		
Balance, beginning of the period	$(21,442)	$(43,890)
Other comprehensive income / (loss)	(27,270)	22,448
Balance, end of the period	$(48,712)	$(21,442)

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 and infrastructure facilities, through investments in securities of subsidiaries including limited partnerships and other trusts which carry on these businesses. The activities of the subsidiaries may be financed through equity contributions, interest bearing notes and third party project debt as described in the notes to the consolidated financial statements.

On October 27, 2009, Algonquin Power Income Fund (the "Fund") completed a reverse take-over transaction (the "Transaction") of Hydrogenics Corporation ("Hydrogenics") which resulted in the Fund's Unitholders becoming shareholders in Hydrogenics which was immediately renamed Algonquin Power & Utilities Corp. As a result, the Fund itself became a wholly owned subsidiary of APUC. The transaction did not result in any change to the underlying business operations of the Fund. For accounting purposes APUC is considered a continuation of the Fund and as such, these consolidated financial statements follow the continuity of interests method of accounting. The Transaction and its accounting treatment are more fully described in note 3.

Up to December 21, 2009, the Fund was managed by Algonquin Power Management Inc. ("APMI") (see note 16).

APUC's power generation business unit conducts business under the name Algonquin Power. Algonquin Power owns 42 renewable energy facilities and 11 high efficiency thermal energy facilities representing more than 400 MW of installed electrical generation capacity. APUC's Water Utility Services business unit conducts business under the name of Liberty Water. Liberty Water owns 17 regulated utilities in the United States of America providing water or wastewater services in the states of Arizona, Texas, Missouri and Illinois. These utility operating companies are regulated investor-owned utilities 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 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 and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined.

1. Significant accounting policies:

(a) Basis of consolidation:

The accompanying audited consolidated financial statements of APUC have been prepared according to Canadian generally accepted accounting principles ("GAAP"), applied on a consistent basis, and includes the accounts of APUC and its wholly owned subsidiaries and variable interest entities where the Company is the primary beneficiary.

Intercompany transactions and balances have been eliminated.

(b) Cash:

Cash consists of cash deposited at banks.

(c) Short Term Investments:

Short term investments, consist of money market instruments with maturities in January 2010 and are recorded at cost, which approximates current market value. Included in short term investments is an investment of $10,000 which is denominated in US $.

(d) Restricted cash:

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.

(e) Property, plant and equipment:

Property, plant and equipment, consisting of land, facilities and equipment, are recorded at cost. The costs of acquiring or constructing facilities together with the related interest costs during the period of construction are capitalized. Interest costs capitalized for Liberty Water's utilities also include the allowance for equity funds used during construction (note 2(b)).

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

The facilities and equipment, which include the cost of major overhauls, are amortized on a straight-line basis over their estimated useful lives. For facilities these periods range from 15 to 40 years. Facility equipment and overhaul costs are amortized over 2 to 10 years.

(f) Intangible assets:

Power purchase contracts acquired 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 are amortized on a straight-line basis over 40 years.

1. Significant accounting policies: (continued)

(g) 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. Recoverability is measured by comparing the carrying amount of an asset to expected future cash flows. If the carrying amount exceeds the expected future cash flows, the asset is written down to its fair market value.

(h) Other long-term liabilities:

Other long-term liabilities include advances in aid of construction. Certain of APUC's water and wastewater utilities are provided with advances through contributions from customers, real estate developers and builders for water and sewage main extensions in order to extend water and sewer service to their properties. The amounts advanced are generally repayable over a prescribed period based on revenues generated by the housing or development in the area being developed as new customers are connected to and take service from the utilities. Generally, advances not refunded within the prescribed period are not required to be repaid. The estimated amount of contributions that are ultimately not refunded is credited to Property, plant and equipment. APUC also receives contributions in aid of construction with no repayment requirements in which case the full amount is immediately treated as a capital grant and netted against property, plant and equipment.

The estimated amount of contributions that are expected to be ultimately refunded is recorded as Advances in Aid of Construction in other long-term liabilities.

Other long-term liabilities also include deferred water rights. Deferred water rights result from 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.

Other long term liabilities also include customer deposits. Customer deposits result from the Liberty Water's utilities' obligation by its respective state regulator to collect a deposit from each customer of its facilities when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement.

(i) Deferred costs:

Deferred costs consist of the costs of arranging the Fund's credit facility.

1. Significant accounting policies: (continued)

(j) Long-term investments:

Investments in which APUC has significant influence but not control or joint 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 and deficit. All other equity investments and notes receivable where APUC does not have significant influence or control are accounted for under the cost method. Under the cost method of accounting, investments are carried at cost and are adjusted only for other-than-temporary declines in value and additional investments.

(k) Recognition of revenue:

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

Water reclamation and distribution revenues are recorded when processed or delivered to customers.

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 are recognized based on actual tonnage at the expected price for the contract year and any amount billed in excess of the expected rate is deferred.

Interest from long-term investments is recorded as earned.

(l) Foreign currency translation:

APUC's policy for translation of foreign operations depends on whether the foreign operations are considered integrated or self-sustaining. APUC's foreign operations, other than Liberty Water, are considered integrated and translated into Canadian dollars using the temporal method whereby current rates of exchange are used for monetary assets and liabilities, historical rates of exchange for non-monetary assets and liabilities and average rates of exchange for revenues and expenses, except amortization which was translated at the rates of exchange applicable to the related assets. Gains and losses resulting from these translation adjustments were included in income.

Liberty Water's utilities are considered self-sustaining foreign operations since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. These self-sustaining 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 are reported as a component of Other Comprehensive Income in the Consolidated Statement of Comprehensive Income.

1. Significant accounting policies: (continued)

(m) Asset retirement obligations:

The fair value of estimated asset retirement obligations is recognized in the consolidated balance sheet when identified and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in amortization expense on the Consolidated Statements of Operations. 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. Actual expenditures incurred are charged against the accumulated obligation. Based on the APUC's assessments the Company does not have any significant asset retirement obligations and therefore no provision for retirement obligations has been recorded in 2009 and 2008.

(n) Income taxes:

Income taxes are accounted for using the asset and liability method. Future 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. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the year that includes the date of enactment or substantive enactment.

The operations of the APUC are complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which it operates are continually changing. As a result, there are usually some tax matters in question that result in uncertain tax positions. The Company recognizes income tax benefits of uncertain tax filing positions when it is more likely than not that the ultimate determination of the tax treatment of the position will result in that benefit being realized.

A valuation allowance is recorded against future tax assets to the extent that it is considered more likely than not that the future tax asset will not be realized.

(o) Financial instruments

APUC has classified its cash, short term investments, accounts receivable, restricted cash, accounts payable and accrued liabilities and distribution / dividend payable as held-for-trading, which are measured at fair value. Notes receivable are classified as loans and receivables, which are measured at amortized cost as there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are classified as other financial liabilities, which are measured at amortized cost, using the effective interest method. APUC reviews the fair market value of financial instruments on a regular basis and whenever events or changes in circumstances indicate that the carrying value may not be recoverable an impairment loss is recognized.

1. Significant accounting policies: (continued)

(o) Financial instruments: (continued)

Transaction costs that are directly attributable to the acquisition or issuance of financial assets or liabilities are accounted for as part of the respective asset or liability's carrying value at inception. Transaction costs for items classified as held-for-trading are expensed immediately. Costs considered as commitment fees paid to financial institutions are recorded in deferred costs, and amortized on a straight-line basis over the term of the debt facility.

APUC has entered into forward foreign exchange contracts as one method of managing its exposure to the US dollar as significant cash flows are generated in the US. Under these forward exchange contracts, APUC sells specific amounts of currencies at predetermined dates and exchange rates. Cash flows from these instruments are matched to the related anticipated operational cash flows. These contracts are measured at fair value and the change in fair value is included in the Consolidated Statements of Operations.

At December 31, 2006, APUC ceased designating its foreign exchange contracts as hedges and recorded the fair value of those contracts of $11,167 as derivative assets and deferred credits. Upon the adoption of the new standards on financial instruments on January 1, 2007, the deferred credits balance of $11,167 was transferred into Accumulated Other Comprehensive Income. The balances from Accumulated Other Comprehensive Income are released as the contracts are settled. At December 31, 2009 there are no longer any amounts remaining in accumulated other comprehensive income related to these foreign exchange contracts (2008 – a gain of $1,789).

In 2006, a wholly owned subsidiary of APUC, Algonquin (AirSource) Power LP ("Airsource"), entered into a fixed for floating interest rate swap until September 2015 in a notional amount which corresponds to the outstanding balance of the Airsource credit facility in order to reduce the interest rate variability on its senior debt facility. APUC has elected not to use hedge accounting for the swap transaction and records the fair value of the swap on the Consolidated Balance Sheets. Any gain or loss in fair value is recognized in the Consolidated Statements of Operations.

(p) 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 recoverability of notes receivable and long-term investments, the recoverability of future tax assets, the portion of advances in aid of construction payments that will not be repaid, assessments of asset retirement obligations, and the fair value of financial instruments and derivatives. 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. Adoption of new accounting standards and recent accounting pronouncements

(a) CICA Section 3064 – Goodwill and intangible assets

Effective January 1, 2009, APUC has adopted the CICA Handbook Section 3064, Goodwill and intangible assets. Section 3064 states that upon their initial identification, intangible assets are to be recognized as assets only if they meet the definition of an intangible asset and the recognition criteria. This section also provides further information on the recognition of internally generated intangible assets. As for subsequent measurement of intangible assets, goodwill, and disclosure, Section 3064 carries forward the requirements of the old Section 3062, Goodwill and Other Intangible Assets. The effect of adopting Section 3064 resulted in no changes to the consolidated financial statements of APUC.

(b) Accounting for rate regulated operations

Effective October 1, 2009, APUC retrospectively adopted rate regulated accounting for Canadian GAAP reporting in its Liberty Water utilities following 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 Canadian 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. Items to which regulatory accounting requirements apply include deferred rate case costs, and capitalization of allowance for equity funds used during construction of regulated capital projects.

Deferred rate case costs relate to costs incurred by the APUC's utilities to file, prosecute and defend rate case applications and which the utility expects to receive prospective recovery through its rates approved by the regulators. Under ASC 980 these costs are capitalized and amortized over the period of rate recovery granted by the regulator while they are expensed under Canadian GAAP for non-regulated entities.

Under ASC 980, allowance for funds used during construction projects 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. It 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). Prior to the adoption of ASC 980, APUC capitalized interest costs directly attributable to the construction of these assets but did not capitalize the allowance for equity funds used during construction projects.

2. Adoption of new accounting standards and recent accounting pronouncements (continued)

(b) Accounting for rate regulated operations (continued)

The effect of adopting rate regulated accounting on previously reported amounts is as follows:

	Year-ended December 31, 2008		
	Balance as previously reported	Adjustment	Balance as restated
Other assets	971	1,053	2,024
Property plant and equipment	804,965	385	805,350
Future tax asset	3,304	(410)	2,894
Future income tax liability	85,654	150	85,804
Deficit	(359,547)	878	(358,669)

The impact on earnings for the year ended December 31, 2009 was not material.

(c) EIC 173 – Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

Effective January 1, 2009, APUC adopted EIC 173, Credit Risk and Fair Value of Financial Assets and Financial Liabilities, which clarifies that the credit risk of counterparties should be taken into account in determining the fair value of derivative instruments. EIC 173 has been applied retrospectively without restatement of prior periods to all financial assets and liabilities measured at fair value. The impact of adopting EIC 173 was a decline of $2,542 to the recorded amount of the financial derivative liability and an increase of $494 in future income tax liability at December 31, 2008 and a $2,048 decrease in deficit.

(d) CICA Handbook Section 3862 - Financial Instruments Disclosure

Effective for the 2009 annual reporting period, the Company adopted amendments to the CICA Handbook Section 3862, Financial Instruments Disclosure. This amended section improves financial instrument fair value measurement and liquidity risk management disclosures. The amendments require an entity to classify fair value measurements using a fair value hierarchy in levels ranging from 1 to 3 that reflect the significance of the inputs used in making these measurements. Level 1 represents fair value measurements for which the inputs are quoted prices in active markets for identical assets or liabilities. Level 2 represents inputs other than quoted prices that are observable either directly or indirectly. Level 3 represents inputs that are not based on observable market data. The use of observable and unobservable inputs is reflected in the fair value hierarchy assessment. The availability of observable inputs can vary based upon the financial instrument and a variety of factors, such as the instrument type, market liquidity, and other specific characteristics particular to the financial instrument. To the extent that the valuation is based on models or inputs that are less observable or unobservable in the market, the determination of fair value requires more judgment by management. The amendments also provide clarification about the required liquidity risk disclosures. Upon application by the Company, the fair value hierarchy level used in the determination of the fair market value of its derivative liabilities has been disclosed in Notes 19 and 26.

3. Unit for share exchange (the "Unit Exchange Offer")

In order to effect a change in business structure from an income trust to a corporation, on October 27, 2009 the Fund's unitholders exchanged 100% of the outstanding trust units of the Fund for a new class of common shares ("New Common Shares") APUC, (formerly Hydrogenics Corporation or Hydrogenics), on a one for one basis. Immediately prior to this exchange, under a Plan of Arrangement, Hydrogenics transferred all of its operations and substantially all its assets and liabilities to a newly created company ("New Hydrogenics"). The pre-existing publicly traded shares of Hydrogenics were contemporaneously redeemed for shares of New Hydrogenics and thus the pre-existing publicly traded shares of Hydrogenics no longer exist. As a result of the Unit Exchange Offer, APUC paid New Hydrogenics $10,813 and has accrued an additional amount of $494 as a final closing adjustment. The transaction resulted in the Unitholders of the Fund indirectly holding their interest in the Fund as shareholders of APUC. Excluding shares issued under the CD Exchange Offer (as defined and described below), the number of common shares of APUC outstanding immediately after completion of the Unit Exchange Offer is exactly the same as the number of the Fund's trust units outstanding immediately before the Unit Exchange Offer.

Accounting treatment of the Unit Exchange Offer

The Unit Exchange Offer is required to be accounted for as a change in business form using the continuity of interests method of accounting in accordance with Emerging Issues Committee abstract 170, "Conversion of an Unincorporated Entity to an Incorporated Entity". Under the continuity of interests method of accounting, the transfer of the assets, liabilities and equity of the Fund to APUC are recorded at their net book values as at the effective date of the Transaction. As a result, for accounting purposes, APUC is required to be accounted for as though it were a continuation of the Fund but with its capital reflecting the exchange of APUC Shares for Trust Units and therefore certain terms such as shareholder/unitholder, dividend/distribution and share/unit may be used interchangeably throughout these consolidated financial statements. For the periods reported up to the effective date of the Unit Exchange Offer, all payments to unitholders were in the form of trust unit distributions, and after that date all payments to shareholders are in the form of dividends.

Comparative figures presented in the consolidated financial statements of APUC include all amounts previously reported by the Fund. In addition, a future tax asset of $66,954 related to the tax attributes of Hydrogenics Corporation was recognized on the transaction date. 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 paid to New Hydrogenics was reflected as a deferred credit of $55,647 on the transaction date to be recognized in income as an income tax expense recovery as the future income tax assets are utilized. As a result of the corporatization transaction, APUC also recorded an increase to future tax liabilities. This adjustment reflects the tax impact of recording future tax assets and liabilities for temporary differences that are reversing or settling prior to 2011 which were previously not recorded since prior to the transactions these temporary difference reversals were not previously expected to be taxed in the Fund.

APUC expensed corporatization costs of $3,460 during 2009 in relation to the Unit Exchange Offer.

Contemporaneously with the Unit Exchange Offer a convertible debenture exchange offer ("the CD Exchange Offer) was made by APUC to debentureholders of the Fund. The CD Exchange Offer is more fully described in note 11.

4. Acquisitions

(a) Future acquisition of electrical generation and regulated distribution utility

In 2009, APUC entered into an agreement to co-acquire an electrical generation and regulated distribution utility through a strategic partnership with Emera Inc. (“Emera”). APUC and Emera each own 50% of the newly formed California Pacific Electric Company (“Calpeco”), which has agreed to acquire the California-based electricity distribution and related generation assets (the “California Utility”) of NV Energy, Inc. for a purchase price of approximately US $116 million, subject to certain working capital and other closing adjustments. APUC and Emera will jointly own and operate the California Utility through Calpeco. The California Utility currently provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. The transaction is subject to state and federal regulatory approval which is expected to occur in the later part of 2010.

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

As of December 31, 2009, APUC has incurred costs of $1,084 related to the strategic partnership with Emera. These costs are recorded as deferred transaction costs and are included in other assets on the Consolidated Balance Sheet.

(b) Entrada Del Oro Sewer Company

In 2008, the Company entered into an agreement to acquire the shares of Entrada Del Oro Sewer Company located in Arizona, for $707 (US$670).

In accordance with the purchase and sale agreement, APUC is required to make additional payments to the previous owners for each additional customer connected to the utility. These payments continue until 2018. As of December 31, 2009, APUC has paid $87 (U.S. $78) (2008 - $nil) as a growth premium, and increased long term investments and notes receivable by a similar amount.

(c) Highground Capital Corporation

On August 1, 2008, the Fund issued 3,507,143 trust units pursuant to an agreement entered into on June 27, 2008 between the Company, Highground Capital Corporation (“Highground”) and CJIG Management Inc. (“CJIG”), which is the manager of Highground and a related party of the Company controlled by the shareholders of APMI. Under the agreement, CJIG acquired all of the issued and outstanding common shares of Highground and APUC issued 3,507,143 trust units of the Fund of which 3,065,183 trust units were received by Highground shareholders as part of the transaction with the remaining trust units being retained by CJIG.

4. Acquisitions (continued)

(c) Highground Capital Corporation (continued)

The Company's final consideration to be received for the trust units issued is dependent on the proceeds realized from liquidation of certain Highground investments. The Company's final consideration will be equal to the lesser of (a) $26,970 plus 50% of the amount, if any, of the value of the assets formerly owned by Highground after payment of the transaction costs is in excess of $26,970 and (b) the value of all of the assets formerly owned by Highground after payment of the transaction costs, with the value of any non-cash securities received by the Company being determined through negotiation between the Directors of the Company and CJIG.

The Fund initially recorded the units issued at their fair value of $7.69 per unit which, net of transaction costs of $767, resulted in proceeds of the units being initially recorded at a value of $26,203. By December 31, 2009, the Company has received consideration and issued trust units as follows:

Consideration received:	
Cash received in 2008	$20,617
Cash received in 2009	983
Twin Falls Note Receivable	793
Retirement of certain long term liabilities of the Fund:	
AirSource Development Note Receivable	1,600
AirSource Participation Agreement	1,400
Brampton Co-generation Inc. capital lease receivable	1,793
	$27,186
Trust units issued:	
Trust units issued	$27,953
Transaction costs	(767)
	$27,186

During 2009, APUC received $983 from CJIG as APUC's share of the 50% of additional proceeds from the further liquidation of the assets held by Highground in excess of $26,970. This has been recorded as an increased amount assigned to the trust units originally issued.

The remaining investments, formerly held by Highground, currently consist of two non-liquid debt assets having a book value of $2,400. APUC's 50% share of any additional proceeds from liquidation of the remaining Highground assets will be recorded as additional proceeds when received from CJIG in future periods.

Included in transaction costs is a fee of $240 paid to APMI in respect of its role in completing the transaction (see note 17).

4. Acquisitions (continued)

(d) Campbellford Partnership

On April 2, 2008, the Company acquired the remaining 50% interest in the Campbellford Partnership not already owned by the Company for net cash consideration of $7,149. The Campbellford Partnership owns a 4 megawatt hydroelectric generating station on the Trent River near Campbellford, Ontario. The acquisition has been accounted for as a step acquisition using the purchase method of accounting. Under the purchase method total assets, liabilities and earnings from operations of the Campbellford partnership are included in the Company's consolidated financial statements since the date of acquisition.

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

Working capital (net of cash received of $233)	$ 128
Reserve funds	112
Plant and equipment	8,114
Intangible asset	969
Future income tax liability	(2,174)
Total cash consideration	$ 7,149

The intangible asset represents the value of the power purchase agreement with Ontario Electricity Financial Corporation. This asset will be amortized over its expected useful life of 11 years.

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

In 2009, APUC entered into definitive agreements to purchase certain electrical generating facility assets including 36.8MW of hydroelectric generating capacity located in New Brunswick and Maine. The acquisition consists of three hydroelectric generating stations, most notably the 34.5MW Tinker Hydroelectric station located on the Aroostook River near the Town of Perth-Andover, New Brunswick. The acquisition also includes five thermal generating stations and certain regulated NB ISO transmission lines located in proximity to the generating facilities. On January 13, 2010, APUC completed the acquisition after satisfying the conditions of the acquisition including regulatory approval for a total cost of approximately $40,000, subject to closing adjustments. The acquisition will be financed out of the Short Term Investments. As of December 31, 2009, APUC incurred costs of $390 related to this acquisition. These costs are recorded as deferred transaction costs and are included in other assets on the consolidated balance sheet.

In connection with the Tinker Acquisition, on February 4, 2010, APUC acquired a related energy services business for a total cost of approximately $1,000. The energy services business retails the electrical generation of the Tinker Acquisition to commercial and industrial customers in northern Maine.

4. Acquisitions (continued)

In accordance with the purchase and sale agreements of Rio Rico Utilities ("Rio Rico"), the Company has been required to make additional payments to the previous owners for each additional customer connected to the facilities.

The amounts paid in accordance with these agreements are as follows:

	2009	2008
Rio Rico	$—	$418
	$—	$418
In United States dollars	$—	$405

As of December 31, 2009 APUC accrued $nil (2008 - $418) as a growth premium, these payments ended in 2008.

5. Other Assets

Other assets consist of the following:

	2009	2008
Regulatory assets	$1,713	$1,155
Wind development assets	788	709
Deferred transaction costs - California Utility (note 4(a))	1,084	—
Tinker Acquisition (note 4 (e))	390	—
Other	201	160
	$4,176	$2,024

Regulatory assets are comprised of deferred rate case costs relate to costs incurred by APUC's utilities to file, prosecute and defend rate case applications and which the utility expects to receive prospective recovery through its rates approved by the regulators. These costs are amortized over the period of rate recovery granted by the regulator.

6. Long-term investments and notes receivable

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

	2009	2008
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	$ 8,344	$ 9,364
25% of Class B non-voting shares of Cochrane Power Corporation	6,544	7,379
45% partnership interest in the Algonquin Power (Rattle Brook) Partnership	3,827	3,881
Investment in Entrada Del Oro (note 4 (b))	709	820
12.1% interest in Tranche A and Tranche B term loan issued by Chapais Énergie, Société en Commandite The loans bear interest at the rate of 10.789% and 4.91%, respectively	3,701	4,034
Airlink Advance (note 17)	666	818
Note Receivable - Twin Falls. The note bears interest at the rate of 6.75%	759	783
Other	—	1,359
	24,550	28,438
Less: current portion	(521)	(485)
Total long term investments and notes receivable	$24,029	$27,953

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

In 2009, APUC wrote off the remaining $1,103 (US - $999) principle balance of the note receivable related to its land fill gas facility which was previously recorded in other long term investments. The balance at December 31, 2009 was $nil.

In 2008, APUC sold its interest in the Brooklyn power generating facility for cash proceeds of $2,954 and recorded $918 as a gain on sale.

7. Property, plant and equipment

Property, plant and equipment consist of the following:

2009

	Cost	Accumulated amortization	Net book value
Land	$ 11,323	$ —	$ 11,323
Facilities	953,826	224,244	729,582
Equipment	30,325	21,880	8,445
	$ 995,474	$ 246,124	$749,350

2008

	Cost	Accumulated amortization	Net book value
Land	$ 11,154	$ —	$ 11,154
Facilities	980,281	195,120	785,161
Equipment	27,855	18,820	9,035
	$1,019,290	$ 213,940	$805,350

Facilities include cost of $94,606 (2008 - $94,606) and accumulated amortization of $25,426 (2008 - $22,889) related to facilities under capital lease or owned by consolidated variable interest entities, and $11,551 (2008 - $13,200) of construction in process. Amortization expense of facilities under capital lease was $2,537 (2008 - $2,489). In addition $5,926 (2008 - $10,458) of contributions received in aid of construction have been credited to facilities cost. Equipment includes cost of $4,096 (2008 - $3,798) and accumulated amortization of $1,857 (2008 - $1,555) related to equipment under capital lease. Amortization expense of equipment under capital lease was $302 (2008 - $241). In 2009, interest of $nil (2008 - $785) was capitalized to facilities within property, plant and equipment.

In December 2009, the APUC decided to dispose of its investments in its last remaining Landfill Gas assets and its biomass joint venture Drayton Valley Power. APUC, therefore tested these investments for recoverability using a net realizeable value valuation technique. As a result, APUC determined that these assets were impaired as at December 31, 2009 and recognized an impairment charge on property, plant and equipment of $5,354 representing the difference between the carrying value of the assets and their net realizeable values. APUC has also recorded $500 related to costs associated with decommissioning the land fill gas facilities and recorded this on the statement of operations with a corresponding increase in other long term liabilities. Both of these assets are currently reported under the Algonquin Power – Thermal Division reporting segment.

The Peel Energy-from-Waste facility experienced an unplanned outage in late January 2010 related due to a failure with second stage boiler tubes and economizer tubes some of which were scheduled for replacement as part of the 2010 capital expenditure plan. APUC intends to accelerate this replacement and simultaneously advance other planned capital maintenance which should allow the facility to make up some of the income expected to be lost during the outage.

8. Intangible assets

Intangible assets consist of the following:

2009

	Cost	Accumulated amortization	Net book value
Power purchase contracts	$119,533	$ 51,333	$68,200
Customer relationships	20,279	2,564	17,715
Licenses and agreements	696	682	14
	$140,508	$ 54,579	$85,929

2008

	Cost	Accumulated amortization	Net book value
Power purchase contracts	$120,900	$ 44,706	$76,194
Customer relationships	23,629	2,441	21,188
Licenses and agreements	696	680	16
	$145,225	$ 47,827	$97,398

9. Derivative assets and derivative liabilities

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates and interest rates (see note 26 – Financial instruments).

In 2008, the Fund entered into a fixed for floating interest rate swap in the notional amount of $100,000 related to a portion of its revolving senior credit facility. APUC has effectively fixed its interest expense on this portion of the facility at a rate of 3.24% in 2009 and 4.18% in 2010. APUC has not designated the swap as a hedge for accounting purposes. The fair value of the interest swap at December 31, 2009 was a liability of $3,260 (2008 - $5,531).

In 2005, AirSource entered into a fixed for floating interest rate swap until September 2015 in order to reduce the interest rate variability on its senior debt facility. The notional amount of the swap is equivalent to the net outstanding amount of the underlying AirSource senior debt. AirSource has effectively fixed its interest expense on its senior debt facility at 5.47%. APUC has not designated the swap as a hedge for accounting purposes. The fair value of the interest swap at December 31, 2009 was a liability of $4,966 (2008 - $11,288).

APUC has entered into foreign exchange contracts as one method to manage its exposure to the U.S. dollar as significant cash flows are generated in the U.S. APUC sells specific amounts of currencies at predetermined dates and exchange rates. Cash flows from these instruments are matched to the related anticipated operational cash flows. Contracts in place at December 31, 2009 amounted to U.S. $39,760 until 2013 at a weighted average exchange rate of $1.02. The fair value of the outstanding forward exchange contracts is a liability of $1,469 at December 31, 2009 (2008 –$16,735).

9. Derivative assets and derivative liabilities (continued)

The current portion of derivative liabilities is $5,775 (2008 - $8,438).

The foreign exchange contracts settle according to the following table:

	Amount	Average exchange rate
2011	26,450	1.01
2012	12,560	1.02
2013	750	1.07
	US $ 39,760	$ 1.02

10. Long-term liabilities

Long term liabilities consist of the following:

	2009	2008
Revolving credit facility: Revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus 0.95%. The effective rate of interest for 2009 was 1.71% (2008 – 4.25%).	$94,000	$137,000
AirSource Senior Debt Financing: Interest rate is equal to bankers' acceptance plus 1% and matures on October 31, 2011. Interest payments only until April 2008 and monthly interest and quarterly principal payments totaling $1,649 (2008 - $1,179). The effective rate of interest for 2009 was 1.78% (2008 – 4.55%).	70,271	71,865
Senior Debt Long Sault Rapids: Interest at rate of 10.2% repayable in blended monthly installments of $402 which commenced in February 1999 and maturing December, 2027.	40,594	41,246
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, 2020. The variable interest rate is determined by the remarketing agent. The effective interest rate for 2009 is 1.44% (2008 – 2.16%).	20,179	23,512
Litchfield Park Service Company Bonds: 1999 and 2001 IDA Bonds. Interest rates of 5.87% and 6.71% repayable in blended semi-annual installments maturing October 2023 and October 2031. Principal payments of U.S. $240 (2008 – U.S. $230) The balance of these notes at December 31, 2009 was U.S. $4,325 and U.S. $7,983, respectively (2008 – U.S. $4,527 and U.S. $8,077).	12,936	15,436
Senior Debt Chute Ford: Interest rate of 11.6% repayable in monthly installments of $64 which commenced in February 1996 and maturing April, 2020.	4,580	4,795
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, 2020 and December, 2017. The balance of these notes at December 31, 2009 was US$1,478 and US$102 respectively (2008 – US$1,650 and US$111).	1,707	2,125

10. Long term liabilities (continued)

	2009	2008
Bonds Payable: Obligation to the City of Sanger due October 1, 2011 at interest rates varying from 5.45% to 5.55%. U.S. $445 (2008 - U.S. $650).	468	796
Other	37	50
	$244,772	$296,825
Less: current portion	(3,360)	(3,235)
	$241,412	$293,590

On January 16, 2008 the Fund renewed its combined senior secured revolving operating and acquisition credit facilities (the "Facilities") for a three year term with its Canadian bank syndicate. The Facilities have a maturity date of January 14, 2011.

The Facilities are subject to certain covenants which can limit amounts available for borrowing including senior debt to EBITDA (as defined in the agreement). At December 31, 2009, $94,000 (2008 - $137,000) has been drawn on the facility. In addition, the availability of the revolving credit facility has been reduced for certain outstanding letters of credit in amounts totaling $33,108 (2008 - $37,508). Therefore, based on current covenant limitations, the Fund had $52,372 of undrawn committed and available bank facilities resulting in total available and committed bank facilities of $179,575 as at December 31, 2009.

The terms of the credit agreement require the Fund to pay a standby charge of 0.25% on the unused portion of the revolving credit facility and maintain certain financial covenants including debt service ratios and various leverage ratios. The facility is secured by a fixed and floating charge over all Fund entities.

Total long term debt is reported net of deferred financing costs. Each of the facility level debt is secured by the respective facility with no other recourse to APUC or the Fund. 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 the Fund and APUC from specific facilities. As at December 31, 2009 APUC and its subsidiaries were in compliance with all debt covenants.

Interest paid on the long-term liabilities was $9,446 (2008 - $16,189).

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

2010	$ 3,360
2011	164,484
2012	1,567
2013	1,719
2014	1,875
Thereafter	71,767
	$244,772

11. Convertible Debentures

Contemporaneously with the Unit Exchange Offer, on October 27, 2009 (see note 3), holders of the Fund's convertible debentures exchanged their convertible debentures for convertible debentures of APUC (the "New Debentures") or for New Common Shares of APUC resulting in the Fund's debentureholders becoming debentureholders or shareholders of APUC.

Pursuant to the CD Exchange Offer, $63,755 of the outstanding Series 1 debentures of the Fund were exchanged for new Series 1 convertible unsecured subordinated debentures of APUC in a principal amount of $66,943, and $21,209 of the current Series 1 debentures of the Fund were exchanged for 6,607,027 shares of APUC. In addition, all of the outstanding Series 2 convertible debentures of the Fund were exchanged for New Series 2 convertible unsecured subordinated debentures of APUC in a principal amount of $59,967.

Accounting treatment of the CD Exchange Offer

The terms of the CD Exchange Offer are considered a modification of the terms of the existing debentures of the Fund rather than an extinguishment since the present value of the cash flows of the liability component of both the New Series 1 and New Series 2 debentures did not change by more than 10% as compared to the terms of the original debentures exchanged. Accordingly, the consolidated balance sheet reflects the convertible debentures at their original carrying values, net of transaction costs associated with the CD Exchange Offer. These transaction costs are recorded as deferred costs and are amortized to interest expense over the remaining terms of the convertible debentures using the effective interest rate method.

Under the terms of the CD Exchange Offer, the New Series 1 convertible debentures of APUC were issued at a face value of 105% of the principle amount of the original Series 1 debentures of the Fund. The change in conversion price of the New Series 1 convertible debentures under the CD Exchange Offer resulted in the fair value of the conversion feature increasing by $1,179 as compared to the original Series 1 debentures. The change in conversion price of the New Series 2 convertible debentures under the CD Exchange Offer resulted in the fair value of the conversion feature decreasing from the original Series 2 convertible debentures carrying value of $479 to $308. The changes of $1,179 and $171 in the fair value of the conversion features on the Series 1 and Series 2 debentures are recorded as a change in the discount on debt, with an offsetting adjustment to equity. The discounts on debt are treated as additional debt issuance costs which are amortized to interest expense over the remaining terms of the convertible debentures using the effective interest rate method.

In addition, an element of the CD Exchange Offer to the Series 1 convertible debenture holders was an option to convert a portion of Series 1 convertible debentures to equity at a rate of 311.52 APUC Shares for each $1 principal amount of Series 1 convertible debentures. This induced conversion option results in an accounting debt settlement expense based on the value of the additional consideration inherent in the change in conversion ratio which is $1,252 and included in corporatization costs on the consolidated statement of operations. The CD Exchange Offer resulted in the holders of the Series 1 convertible debentures converting $21,209 of the outstanding principal balance of Series 1 convertible debentures into 6,607,027 common shares of APUC.

11. Convertible Debentures (continued):

The pro rata portion of existing deferred financing charges associated with the Series 1 convertible debentures of $306 is recorded as a component of the amount recorded for the common shares issued on conversion. In addition, a proportionate allocation of the total deferred transaction costs associated with the CD Exchange Offer is recorded as part of the issuance costs of the new APUC shares. APUC incurred transaction costs of $1,453 related to the CD Exchange Offer for the Series 1 convertible debentures of which $1,090 is allocated to the convertible debentures as debt issuance costs and $363 has been allocated to issuance costs related to the new APUC shares. APUC also incurred costs of $1,453 related to the CD Exchange Offer for the Series 2 convertible debentures which has been allocated to the convertible debentures as debt issuance costs.

The exchange of $63,755 of Series 1 convertible debentures that were not converted to shares, after adjustment for the 5% premium included in the CD Exchange Offer, resulted in an increase in the principal balance of the new Series 1 convertible debentures to $66,943. The increase of $3,188 is accounted for as additional debt issuance costs and is amortized to interest expense over the term of the new convertible debentures using the effective interest rate method.

On December 2, 2009, APUC issued 63,250 of convertible unsecured subordinated debentures (Series 3) at a price of $1 per debenture for gross proceeds of $63,250 and net proceeds of $60,518. The debentures are due June 30, 2017 and bear interest at 7.00% per annum, payable semi-annually in arrears on June 30 and December 31 each year. The convertible debentures are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares per $1 principal amount of debentures. The debentures can not be redeemed by APUC on or before December 31, 2012. APUC performed an evaluation of the embedded holder option and determined that its value was $4,275 and as a result this portion of the debenture is classified as equity with the remaining amount classified as a liability. The liability component of convertible debentures increases to their face value over the term of the debentures. The offsetting charge to earnings is classified as interest expense on the Consolidated Statements of Operations.

Total interest paid on the convertible debentures in 2009 was $9,696 (2008 - $9,370).

11. Convertible Debentures (continued):

2009	New Series 1	New Series 2	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$ 4.08	$ 6.00	$ 4.20	
Carrying value at December 31, 2008	83,178	57,249	—	140,427
Issued pursuant to December 2, 2009 offering	—	—	63,250	63,250
Change in equity component (Note13)	(1,179)	171	(4,275)	(5,283)
Conversion to shares (Note13), net of costs	(21,209)	(33)	—	(21,242)
Deferred issue costs	(784)	(1,453)	(2,731)	(4,968)
Amortization and accretion	722	307	44	1,073
Carrying value at December 31, 2009	$ 60,728	$ 56,241	$ 56,288	$173,257
Face value at December 31, 2009	$ 66,943	$ 59,967	$ 63,250	$190,160

2008	Series 1	Series 2	Total
Maturity date	2011 July 31	2016 November 30	
Interest rate	6.65%	6.20%	
Conversion price per unit	$ 10.65	$ 11.00	
Carrying Value, December 31, 2007	$82,616	$ 56,971	$139,587
Amortization and accretion	562	278	840
Carrying value at December 31, 2008	$83,178	$ 57,249	$140,427
Face Value at December 31, 2008	$84,964	$ 60,000	$144,964

12. Other long-term liabilities

Other long term liabilities consist of the following:

	2009	2008
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 February 2013	$ 456	$ 375
Advances in aid of construction	14,952	17,500
Customer deposits	2,405	3,020
Deferred water rights inducement	3,089	3,170
Other	5,351	5,795
	26,253	29,860
Less: current portion	(1,025)	(1,001)
	$25,228	$28,859

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

2010	$ 1,025
2011	694
2012	107
2013	9
2014	—
Thereafter	24,418
	$26,253

Interest paid on other long-term liabilities was $37 (2008 - $52).

13. Shareholders' equity/Unitholders' equity

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 outstanding.

On October 27, 2009, pursuant to the Unit Exchange Offer (see note 3), the Fund's unitholders exchanged 100% of the outstanding trust units of the Fund for a new class of common shares ("New Common Shares") of Algonquin Power & Utilities Corp. ("APUC") on a one for one basis. As a result, the existing unitholders of the Fund became shareholders of APUC and the Fund became a subsidiary of APUC.

The Fund's Declaration of Trust provides that an unlimited number of units may be issued. Each unit represents an undivided beneficial interest in any distribution from the Fund and in the net assets in the event of termination or wind-up. All units are the same class with equal rights and privileges. Trust units are redeemable at the holder's option at amounts related to market prices at the time subject to a maximum of $250 in cash redemptions in any particular calendar month, subject to the ability of the Fund to waive the maximum and pay further amounts by way of cash. Redemptions in excess of this amount shall be paid by way of a distribution in kind of a pro rata amount of certain of the Fund's assets, including the securities purchased by the Fund, but not to include the generating facilities.

On December 2, 2009, APUC issued 6,877,000 common shares at $3.35 per common share for gross proceeds of $23,038 before issuance costs of $1,495, (net of tax $1,002) for net proceeds of $21,533.

13. Shareholders' equity/Unitholders' equity (continued):

At a special meeting of Exchangeable Unitholders of Algonquin (AirSource) Power LP in December 2009, amendments were approved to amend the agreements related to the Exchangeable Units to allow the exchange of Exchangeable Units for common shares of APUC, as opposed to units of the Fund, and to change the definition of "Redemption Date" as set out in the Partnership Agreement. As a result of these changes, APUC exercised the compulsory acquisition provisions of the Exchangeable Units on December 31, 2009 and all of the remaining outstanding Exchangeable Units were exchanged for 532,074 common shares of APUC, as per the formula set out in the original agreements. As a result, there are no outstanding Exchangeable Units as at December 31, 2009 and consequently the non-controlling interest balance at December 31, 2009 is reduced to $nil (2008 - $12,548). The non-controlling interest of $2,737 (2008 – ($3,142)) in the statement of operations represents the allocation of earnings to the exchangeable unitholders (AirSource Power LP) for the year ended December 31, 2009 prior to the conversion of Exchangeable Units for common shares of APUC.

Shareholders equity/Unitholders' Equity consists of the following:

	2009	2008
Balance of Trust units, beginning of period	$721,953	$691,734
Issued on conversion of Airsource exchangeable units	14,487	4,016
Conversion of convertible debentures, net of costs	21,825	—
Common Share issue, net of costs	22,026	—
Issued pursuant to Highground transaction (Note 4 (c))	—	26,203
Proceeds from liquidation of Highground assets (Note 4 (c))	983	—
Balance of Trust units, end of the period		$721,953
Balance of Shares, end of the period	$781,274	
Trustee Loans (Note 17)	—	(217)
Equity component of convertible debentures (Note 11)	5,763	479
Unitholders' equity, end of period		$722,215
Shareholders' equity, end of period	$787,037	

13. Shareholders' equity/Unitholders' equity (continued):

Number of common shares/trust units:

	2009	2008
Trust units, beginning of period	77,574,372	73,644,356
Issued on conversion of Algonquin (AirSource) Power LP exchangeable units	2,005,721	422,873
Conversion of convertible debentures (Note 11)	6,607,027	—
Issued pursuant to Highground transaction (Note 4(c))	—	3,507,143
Issued pursuant to offering	6,877,000	—
Trust units, end of period		77,574,372
Common shares, end of period	93,064,120	

14. Income taxes

The Unit Exchange Offer (Note 3), together with changes in tax rates enacted in December 2009, resulted in APUC recognizing a future income tax asset of $60,014 and a deferred credit in relation to this asset of $49,879 as at December 31, 2009. The accounting for the deferred credit is in accordance with EIC 110 – "Accounting For Acquired Future Tax Benefits In Certain Purchase Transactions That Are Not Business Combinations". The credit is being amortized to income tax expense in proportion to the net reduction in the future income tax asset that gave rise to the deferred credit. Current and future income taxes have been provided in respect of taxable income and temporary differences related to the Company and its subsidiaries.

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 33% (2008 - 33.05%). The differences are as follows:

	2009	2008
Expected income tax expense / (recovery) at Canadian statutory rate	5,302	(7,228)
Increase (decrease) resulting from:		
Accounting losses (income) of the Fund taxed at the unitholder level	(20,790)	4,513
Differences in tax rates in subsidiaries and changes in tax rates	(1,848)	426
Change in valuation allowances	10,688	21,239
Foreign exchange loss on intercompany items	(13,464)	(18,329)
Non deductible expenses and other	2,185	(313)
Income tax expense / (recovery)	$(17,927)	$ 308

14. 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 future tax assets and future tax liabilities at December 31, 2009 and 2008 are presented below:

	2009	2008
Future tax assets:		
Non-capital losses, investment tax credits, currently non-deductible interest expense and financing costs	$ 104,455	$ 25,355
Unrealized foreign exchange differences on US entity debt	25,138	11,674
Customer advances in aid of construction	5,393	6,768
Foreign exchange hedges and interest rate swaps	2,865	3,940
Total future tax assets	137,851	47,737
Less: Valuation allowance	(35,393)	(24,705)
Total future tax assets	102,458	23,032
Future tax liabilities:		
Property, plant and equipment	(96,960)	(95,157)
Intangible assets	(8,409)	(9,861)
Other	(2,131)	(2,115)
Total future tax liabilities	(107,500)	(107,133)
Net future tax liability	$ (5,042)	$ (84,101)

Classified in the financial statements as:

	2009	2008
Future current income tax asset	$ 14,566	$ —
Future non-current income tax asset	61,219	2,894
Future current income tax liability	(913)	(1,191)
Future non-current income tax liability	(79,914)	(85,804)
	$ (5,042)	$(84,101)

As at December 31, 2009, the Company had non capital loss carryforwards available to reduce future years taxable income, which expire as follows:

Year of expiry	Non-capital loss carryforward
2010	$ 19,390
2014	29,788
2015	37,487
2019	116
2020 and onwards	175,323
	$ 262,104

15. Loss/(gain) on derivative financial instruments

Loss/(gain) on derivative financial instruments consist of the following:

	2009	2008
Unrealized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$(15,682)	$25,473
Interest swaps	(7,424)	16,953
Total unrealized loss/(gain) on derivative financial instruments	$(23,106)	$42,426
Realized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ 284	$ (5,077)
Interest rate swaps	5,504	399
Total realized loss/(gain) on derivative financial instruments	$ 5,788	$ (4,678)
Loss/(gain) on derivative financial instruments	$(17,318)	$37,748

16. Management internalization

On December 21, 2009, the Board of Directors of APUC (the “Board”) reached an agreement with APMI to internalize all management functions of the Fund which were provided by APMI. APUC acquired APMI’s interest in the management services agreement, with consideration to be paid in the form of issuance of 1,158,748 APUC shares (the “Shares”). For accounting purposes, the expense has been measured at $4,693 using a price for each share of $4.03, the adjusted closing market price on December 21 2009, the date the agreement was ratified.

In accordance with the policies of the Toronto Stock Exchange, approval of the issuance of the Shares will be sought from shareholders at the next annual general meeting.

17. Related party transactions

In addition to the transactions described in note 4 (c) with APMI, the following related party transactions occurred:

Up to December 21, 2009, APMI provided management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. In 2009 and 2008, APMI was paid on a cost recovery basis for all costs incurred and charged $850 (2008 - $893). APMI was also entitled to an incentive fee of 25% on all distributable cash (as defined in the management agreement) generated in excess of $0.92 per trust unit. During 2009 $nil (2008 - $nil) was earned by APMI as an incentive fee.

As part of the project to re-power the Sanger facility, the Fund entered into an agreement with APMI to undertake certain construction management services on the project. APMI is entitled to a development supervision fee plus a performance based contingency fee for its construction management role on the project. During 2009, APMI was paid $nil (2008 - $23) for development supervision. During 2008, the Fund accrued $674 as the final fee owed to APMI with respect to this project. This fee has been accrued and is included in accounts payable on the consolidated balance sheet.

APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a net basis. Base lease costs for 2009 were $331 (2008 - $296).

On March 10, 2008, the Company advanced $225 to the Trustees for purposes of enabling the Trustees to purchase additional Units of the Company. The loans were subject to promissory notes issued in favour of the Company which were repayable upon demand and were recorded as a reduction in Trust Units on the consolidated balance sheet. On October 22, 2009 the loans were fully repaid. During 2008 a principal repayment of $8 was made.

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Airlink. In 2004, APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC will have priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the year, APUC incurred costs in connection with the use of the aircraft of $367 (2008 - $332) and amortization expense related to the advance against expense reimbursements of $153 (2008 - $90). At December 31, 2009, the remaining amount of the advance was $666 (2008 - $818).

Up to August 1, 2008, the Company had project debt from Highground (previously Algonquin Power Venture Fund) in the amount of $3,000 related to the St. Leon facility. Highground advanced $1,600 at a rate of 11.25% as part of the initial financing of the St. Leon facility and advanced $1,400 at a rate of 9.25% during the first quarter of 2007. These amounts have now been eliminated on the Consolidated Balance Sheet of the Company due to the acquisition of Highground (Note 4 (c)).

Up to July 31, 2008, Highground was paid $150 (2007 - $150) in interest related to debt associated with the St. Leon facility. Some of the directors and shareholders of APMI were also directors, officers and shareholders of the manager of Highground.

In accordance with the construction services agreement related to the St. Leon facility, a company controlled by APMI was paid a final payment of $134 in 2008 for construction services.

17. Related party transactions (continued)

Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), an indirect subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing June 17, 2008 growing to a maximum of 10% by year 15. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units are entitled to cash distributions of $292 for the year ended December 31, 2009 (2008 - $173).

Pursuant to the agreement entered into on June 27, 2008 between the Company, Highground and CJIG (Note 4(c)), APMI was entitled to a fee of approximately $240 from the Company. This fee was paid in 2009.

APMI is entitled to 50% of the cash flow above 15% return on investment for the BCI project pursuant to its project management contract. During 2009 and 2008, no amounts were paid under this agreement. However, APMI earned a construction supervision fee in 2008 of $100 in relation to the development of this project.

18. Commitments and Contingencies

(a) Land and Water Leases

Certain of the Company's operating entities have entered into agreements to lease either land, water rights or both that are used in the generation of electricity or to pay, in lieu of property tax, an amount based on electricity production. The terms of these leases have varying maturity dates that continue up to 2048. These payments typically have a fixed and variable component. The variable fee is generally linked to actual power production or gross revenue. APUC incurred costs of $2,823 during 2009 (2008 - $3,181) in respect of these agreements for all of its operating entities.

(b) 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. 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.

Legislation in the Province of Quebec requires technical assessments be made of all dams within the province and remediation of any technical deficiencies identified in accordance with the assessment. APUC is in the process of conducting the assessments as required. Based on assessments to date, some of which are preliminary, APUC has estimated potential remedial measures involving capital expenditures of approximately $17,500 which may be required to comply with the legislation and which would be invested over a five year period or longer. APUC continues to explore alternatives to reduce or mitigate these potential capital expenditures, including technical alternatives and cost sharing with other stakeholders.

(c) Commitments

An AirSource affiliate, St. Leon Wind Energy LP ("St. Leon LP") has entered into right-of-way agreements (collectively, the "Land Rights"), with approximately 50 local landowners, providing for a minimum term of 40 years. The Land Rights agreements provide for an annual rent payable per MW-hr generated from turbines installed on the land rented, subject to a minimum payment per wind turbine. Land without wind turbines is leased at a cost on a per acre basis. The total commitment over the term of the St. Leon power purchase agreement is estimated at $3,863.

19. Fair Value of Financial instruments and Derivatives

The carrying amount of APUC's cash, short term investments, accounts receivable, restricted cash, accounts payable and accrued liabilities, and distributions / dividends payable approximate fair market value.

The carrying amount of APUC's long-term investments is dependant on the underlying operations and accordingly a fair value is based on management's best estimate using inputs that are not based on directly observable markets.

APUC has long-term liabilities and convertible debentures at fixed interest rates and variable rates. The estimated fair value of the convertible debentures at current rates would be $198,892 (2008 - $112,494). The book value of the convertible debentures is $173,257 (2008 - $140,427). The estimated fair value of the long-term liabilities would be $247,119 (2008 - $261,328). The book value of the long-term liabilities is $244,772 (2008 - $296,825). The fair value of other long-term liabilities approximates their carrying value.

Advances in aid of construction included in other long-term liabilities (note – 1 (h)) do not bear interest and the amount to be repaid is uncertain and not determinable. The carrying value is estimated based on historical payment patterns.

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 has determined that the carrying value of its short-term financial assets and liabilities approximates fair value at December 31, 2009 and 2008 due to the short-term maturity of these instruments.

20. Cash distributions and cash dividends

All cash distributions and dividends of the Company are made on a discretionary basis as determined by the Board of Directors of the Company. In 2009, the Company paid monthly cash distributions and dividends of $0.02 per unit / per share. For the year ended December 31, 2009, the Company paid cash distributions / dividends to unitholders and shareholders totaling $18,999 (2008 - $56,046) or $0.24 per unit / per share (2008 - $0.75).

Total distributions to the unitholders of the AirSource exchangeable units for 2009 were $323 (2008 - $1,709) which have been recorded as a reduction in non controlling interest on the consolidated Balance Sheet.

21. Non cash working capital

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

	2009	2008
Accounts receivable	$ 6,720	$ (803)
Income tax receivable	395	(1,538)
Prepaid expenses	(1,842)	248
Accounts payable and accrued liabilities	(6,042)	7,950
Current income tax liability	(536)	(128)
	$(1,305)	$ 5,729

22. Basic and diluted net earnings per share

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

	2009	2008
Weighted average shares – basic	79,830,906	75,265,940
Shares issuable on conversion of AirSource exchangeable units	1,499,222	2,042,103
Weighted average shares – diluted	81,330,128	77,308,043

Shares or Trust units issuable on conversion of exchangeable units are calculated at the year end based on the weighted average exchangeable units outstanding during the year and applying the rate of exchange. The shares to be issued as a result of the management internalization and all the convertible debentures are excluded from this calculation as they are anti-dilutive.

23. Interest, dividend and other income

Interest, dividend and other income includes the following items:

	2009	2008
Interest income	$ 710	$ 918
Dividend income	2,928	2,928
Equity income	361	373
Gain on sale of Brooklyn note	—	918
Gain on sale of land and land rights	1,451	700
Other	951	1,186
	$6,401	$7,023

24. Other revenue

Other revenue consists of the following:

	2009	2008
Natural gas sales	$ 588	$ 481
Hydro mulch sales	3,260	3,832
Other	—	36
	$3,848	$4,349

25. Segmented Information

APUC has two broad operating segments: Algonquin Power which owns and operates 42 renewable energy facilities and 11 high efficiency thermal energy facilities representing more than 400 MW of installed electrical generation capacity and Liberty Water which owns and operates 17 regulated utilities in the United States of America providing water or wastewater services in the states of Arizona, Texas, Missouri and Illinois.

Within Algonquin Power there are three divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops the Company's greenfield power generation projects as well as any expansion of the Company's existing portfolio of renewable energy and thermal energy facilities.

Liberty Water provides transportation and delivery of water and wastewater in its service areas.

25. Segmented Information (continued)

Geographic Segments

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:

	2009	2008
Revenue		
Canada	$ 82,364	$ 85,094
United States	104,901	128,702
	$187,265	$213,796
Property, plant and equipment		
Canada	$440,490	$461,982
United States	308,860	343,368
	$749,350	$805,350
Intangible assets		
Canada	$ 47,916	$ 52,513
United States	38,013	44,885
	$ 85,929	$ 97,398
Other assets		
Canada	$ 1,250	$ 799
United States	2,926	1,225
	$ 4,176	$ 2,024

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

Operational segments

APUC's reportable segments are Algonquin Power - Renewable Energy, Algonquin Power - Thermal Energy and Liberty Water. The development activities are reported under Renewable Energy or Thermal Energy as appropriate. For purposes of evaluating divisional performance, the Company allocates the realized portion of the gain on financial instruments to specific divisions. This allocation is determined when the initial foreign exchange forward contract is entered into. The unrealized portion of any gains or losses on derivatives instruments is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. Interest expense is allocated to the divisions based on the project level debt related to the facilities in each division. Interest expense on the revolving credit facility and convertible debentures is reported in the corporate segment. The interest rate swaps relate to specific debt facilities and gains and losses are allocated to operating segments in the same manner as interest expense. The operations and assets for these segments are as follows:

25. Segmented Information (continued)

Operational Segments (continued)

Year ended December 31, 2009

	Algonquin Power			Liberty Water	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	$ 68,227	$ 62,209	$130,436	$ —	$ —	$ 130,436
Waste disposal fees	—	14,468	14,468	—	—	14,468
Water reclamation and distribution	—	—	—	38,513	—	38,513
Other revenue	—	3,848	3,848	—	—	3,848
Total revenue	68,227	80,525	148,752	38,513	—	187,265
Operating expenses	22,279	57,299	79,578	23,158	—	102,736
	45,948	23,226	69,174	15,355	—	84,529
Other administration costs	(243)	(169)	(412)	(226)	(10,924)	(11,562)
Foreign exchange loss	—	—	—	—	1,261	1,261
Interest expense	(6,180)	(543)	(6,723)	(1,526)	(13,138)	(21,387)
Interest, dividend and other income	1,226	3,749	4,975	1,368	58	6,401
Gain / (loss) on derivative financial instruments	2,682	(829)	1,853	343	15,122	17,318
Write down of property plant and equipment	—	(5,354)	(5,354)	—	—	(5,354)
Write down of note receivable	—	(1,103)	(1,103)	—	—	(1,103)
Amortization of property, plant and equipment	(16,934)	(13,087)	(30,021)	(8,557)	—	(38,578)
Amortization of intangible assets	(2,654)	(3,916)	(6,570)	(735)	—	(7,305)
Earnings / (loss) from operations before income taxes, non-controlling interest, and corporatization costs	23,845	1,974	25,819	6,022	(7,621)	24,220
Management internalization costs					(4,693)	(4,693)
Other corporatization costs					(3,460)	(3,460)
Net earnings / (loss) before income taxes, and non-controlling interest	23,845	1,974	25,819	6,022	(15,774)	16,067
Property, plant and equipment	$403,192	$176,171	$579,363	$169,987	$ —	$ 749,350
Intangible assets	30,602	30,436	61,038	24,891	—	85,929
Total assets	451,936	245,582	697,518	203,444	112,451	1,013,413
Capital expenditures	1,114	3,521	4,635	6,174	107	10,916

25. Segmented Information (continued)

Operational Segments (continued)

Year ended December 31, 2008

	Algonquin Power			Liberty Water	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	$ 75,549	$ 82,959	$158,508	$ —	$ —	$158,508
Waste disposal fees	—	15,706	15,706	—	—	15,706
Water reclamation and distribution	—	—	—	35,233	—	35,233
Other revenue	—	4,349	4,349	—	—	4,349
Total revenue	75,549	103,014	178,563	35,233	—	213,796
Operating expenses	22,015	77,221	99,236	21,243	—	120,479
	53,534	25,793	79,327	13,990	—	93,317
Other administration costs	(482)	(141)	(623)	(284)	(9,405)	(10,312)
Foreign exchange loss	—	—	—	—	(4,018)	(4,018)
Interest expense	(8,420)	(974)	(9,394)	(1,045)	(15,849)	(26,288)
Interest, dividend and other income	1,477	3,665	5,142	102	1,779	7,023
Gain / (loss) on derivative financial instruments	(11,869)	1,595	(10,274)	3,482	(30,956)	(37,748)
Amortization of property, plant and equipment	(16,481)	(13,269)	(29,750)	(6,791)	—	(36,541)
Amortization of intangible assets	(2,617)	(3,934)	(6,551)	(754)	—	(7,305)
Net earnings / (loss) before income taxes, and non-controlling interest	15,142	12,735	27,877	8,700	(58,449)	(21,872)
Property, plant and equipment	$418,899	$190,387	$609,286	$196,064	$ —	$805,350
Intangible assets	33,256	34,353	67,608	29,790	—	97,398
Total assets	473,554	265,631	739,185	233,883	5,062	978,515
Capital expenditures	2,275	8,442	10,717	34,587	257	45,561
Acquisition of operating entities	7,149	—	7,149	1,125	—	8,274

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2009 or 2008: Hydro Québec 17% (2008 - 14%), Pacific Gas and Electric 12% (2008 - 14%), Manitoba Hydro 15% (2008 – 15%), and Connecticut Light and Power 18% (2008 - 22%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

26. Financial instruments

a) 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 agreements are used to manage exposure to fluctuations in exchange rates and interest rates. 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.

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 and accounts receivable. The Company limits its exposure to credit risk with respect to cash equivalents by maintaining minimal cash balances and 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 regulated water and wastewater utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of US$2,934 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.

26. Financial instruments (continued)

As at December 31, 2009 the Company's exposure to credit risk for these financial instruments was as follows:

	December 31, 2009	
	Canadian $	US $
Cash and cash equivalents	2,548	236
Short term investments	29,500	10,000
Accounts receivable	10,969	9,175
Allowance for Doubtful Accounts	—	(128)
	$ 43,017	$19,283

There are no material past due amounts in accounts receivable.

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, 2009, in addition to cash on hand of $2,796 the Company had $52,372 available to be drawn on its senior debt facility and $40.0 million in short term investments available to complete the acquisition of three hydroelectric generating assets located in New Brunswick and Maine. The senior credit facility contains covenants which may limit amounts available to be drawn.

	Total	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years
Long term debt obligations	$244,772	$ 3,360	$166,051	$ 3,594	$ 71,767
Convertible Debentures	190,160	—	—	66,943	123,217
Accounts Payable	33,219	33,219	—	—	—
Interest on long term debt obligations	157,705	21,685	38,555	39,723	57,742
Derivative financial instruments:					
Currency Forwards	1,469	—	1,475	(6)	—
Interest Rate Swaps	8,226	5,775	2,025	417	9
Lease Payments	456	145	302	5	4
Other obligations	10,143	515	1,025	1,025	7,578
Total obligations	$646,150	64,699	209,433	111,701	260,317

26. Financial instruments (continued)

Foreign Currency Risk

The Company uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from these 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. Based on the fair value of the forward contracts using the exchange rates as at December 31, 2009, the exercise of these forward contracts will result in the use of $1,084 in fiscal 2011 and result in the use of $385 in cash for the remainder of the hedged period beyond 2011. Assuming a decrease in the strength of the US dollar relative to the Canadian dollar of $0.05 at December 31, 2009 with a corresponding change in the forward yield curve, the fair value of the outstanding forward exchange contracts would increase by $3,976, increasing the expected cash generated during fiscal 2011 by $2,645, and $1,331 for the remainder of the hedged period beyond 2011.

As at December 31, 2009, APUC had US$39,760 in outstanding foreign exchange forward contracts with an average rate of $1.02 and having a fair value liability of $1,469.

The Company has performed sensitivity analysis on its U.S. dollar denominated financial instruments which consist principally of cash US$236, short term investments of US$10,000, net negative U.S. dollar working capital of $2,663 and long-term debt in integrated foreign operations of US$19,645 at December 31, 2009, to determine how a change in the U.S. dollar exchange rate would impact net earnings. As at December 31, 2009, the Company determined that a 5% change in the Canadian dollar against the U.S. dollar, assuming that all other variables, including interest rates, had remained the same, would have resulted in a $604 change in the Company's net earnings as at December 31, 2009.

Interest Rate Risk

The Company is exposed to interest rate fluctuations related to certain of its debt obligations, including certain project specific debt and its revolving credit facility as well as interest earned on its cash on hand. The Company has performed sensitivity analysis on interest rate risk at December 31, 2009 to determine how a change in interest rates would impact equity and net earnings:

- The Company's senior debt facility has a balance of $94,000 as at December 31, 2009. Assuming the current level of borrowings, a 1% change in the variable rate charged would impact interest expense by $940 during the twelve months ended December 31, 2009. Although this underlying debt with the project lenders carries a variable rate of interest tied to Canadian Bank's prime rate, the Company has entered into a fixed for floating interest rate swap related to $100,000 of this debt between June 30, 2008 and December 2010. At December 31, 2009, the fair value of the interest rate swap was a net $3,260 liability. This swap arrangement requires the payment of a fixed rate of interest by the Company in exchange for receipt of a variable rate of interest. These payments form part of the gain or loss on financial instruments on the Consolidated Statements of Operations which reduces volatility in the interest expense on this debt facility through a partial offset for changes to interest expense as a result of market rate fluctuations.

26. Financial instruments (continued)

- The Airsource project debt at the St. Leon facility has a balance of $70,271 as at December 31, 2009. Assuming the current level of borrowings, a 1% change in the variable rate charged would have impacted interest expense by $705 during the twelve months ended December 31, 2009. At December 31, 2009, the fair value of the interest rate swap was a net $4,966 liability. Although this underlying debt with the project lenders carries a variable rate of interest tied to Canadian Bank's prime rate, the Company has entered into a fixed for floating interest rate swap related to this debt until September 2015. This swap arrangement requires the payment of a fixed rate of interest by the Company in exchange for receipt of a variable rate of interest that mirrors the underlying debt's interest payment schedule. These payments form part of the gain or loss on financial instruments on the Statement of Earnings which effectively minimizes volatility in the interest expense on this debt facility through an offset for any change to interest expense as a result of market rate fluctuations.
- The Company's project debt at the Sanger facility has a balance of U.S. $19,200 as at December 31, 2009. Assuming the current level of borrowings, a 1% change in the variable rate charged would impact interest expense by $192 during the twelve months ended December 31, 2009. This analysis assumes that all other variables, in particular foreign currency rates, remain constant.

The following table shows derivative liabilities measured at fair value as of December 31, 2009 on the Company's balance sheet, and the input categories associated with these liabilities:

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value at December 31
Interest rate SWAP – St Leon	$ —	$ 4,966	$ —	$ 4,966
Interest rate SWAP – revolving credit facility	—	3,260	—	3,260
Foreign exchange hedges	—	1,469	—	1,469
	$ —	$ 9,695	$ —	$ 9,695

27. Capital disclosures

The Company 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.

The Company's objectives when managing capital are:

- 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 distributions to Unitholders as well as meet current tax and internal capital requirements.
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders.
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

The Company monitors its cash position on a regular basis to ensure funds are available to meet current operating as well as capital expenditures. In addition, the Company regularly reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

28. Comparative figures

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

Exhibit 99.3



Management's Discussion and Analysis

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

Management of Algonquin Power & Utilities Corp. ("APUC"), the corporation continuing the business of the Algonquin Power Income Fund (the "Fund"), 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, 2009. This 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, 2009 and 2008 and the notes thereto. 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 can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of February 27, 2010.

Caution concerning forward looking statements and non-GAAP Measures

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "outlook", "believes", "anticipates", "continues", "could", "expect", "may", "will", "project", "estimates", "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 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 our actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the continued 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; and the state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. APUC reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. Although APUC 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. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

The terms "adjusted net earnings" and "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA") are used throughout this MD&A. The terms "adjusted net earnings" and Adjusted EBITDA are not recognized measures under Canadian generally accepted accounting principles ("GAAP"). There is no standardized measure of "adjusted net earnings" and Adjusted EBITDA, consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "adjusted net earnings" and Adjusted EBITDA can be found throughout this MD&A.

Conversion to a Corporation

On October 27, 2009, the Fund completed a transaction (the "Unit Exchange Offer") which provided the Fund's unitholders the opportunity to exchange their trust units of the Fund, on a one-for-one basis, for common shares of an existing corporation. This existing corporation, Hydrogenics Corporation, transferred all of its operations and existing shares to a new corporation pursuant to a Plan of Arrangement prior to completion of the Unit Exchange Offer. The name of Hydrogenics Corporation was changed to Algonquin Power & Utilities Corp. following closing of the transaction.

The transaction resulted in the unitholders of the Fund becoming shareholders of APUC, with no changes to the Fund's underlying business operations. Under the continuity of interest method of accounting, APUC's transfer of assets, liabilities and equity of the Fund are recorded at their net book value in APUC's financial statements as at October 27, 2009. As a result of this conversion, certain terms such as shareholder/unitholder and dividend/distribution may be used interchangeably throughout this MD&A. Prior to October 27, 2009, all distributions to unitholders were in the form of trust unit distributions. References to APUC shall mean the Fund with respect to activities and results occurring prior to October 27, 2009 and shall mean APUC with respect to activities and results occurring on or after October 27, 2009.

Overview

APUC is a corporation incorporated under the Canada Business Corporations Act. APUC produces stable earnings through a diversified portfolio of renewable energy and utility businesses owned and operated by its subsidiary entities. APUC conducts its business primarily through two businesses:

The first, conducting business as Algonquin Power Co. ("APCo"), generates electrical energy through a diverse portfolio of clean, renewable power generation and thermal power generation facilities across North America. As at December 31, 2009, APCo owns 41 hydroelectric facilities operating in Ontario, Québec, Newfoundland, Alberta, New York State, New Hampshire, Vermont and New Jersey with a combined generating capacity of 140 MW. APCo also owns a 99 MW wind farm in Manitoba. The renewable energy facilities are generally facilities operating under long term power purchase agreements with major utilities and have an average remaining contract life of 16 years. APCo's 11 thermal energy facilities operate under power purchase agreements ("PPAs") and have an average remaining contract life of 7 years with a combined generating capacity of 321 MW.

The second, Liberty Water Co. ("Liberty Water") provides water and wastewater utility services through 18 water distribution and wastewater utility systems in the United States. Liberty Water provides regulated water distribution and wastewater facilities in Arizona, Illinois, Missouri and Texas. These utility operating companies are regulated investor-owned utilities subject to regulation, including rate regulation, by the public utility commissions of the states in which they operate.

Business Strategy and Recent Developments

APUC's business strategy is to maximize long term shareholder value as a dividend paying, growth oriented corporation actively competing within its clearly defined business sectors. APUC is committed to delivering a total shareholder return comprised of a dividend augmented by capital appreciation arising through growth in earnings and dividends. Through an emphasis on sustainable, long view renewable power and utility investments, over a medium term planning horizon APUC strives to deliver annualized earnings growth exceeding 5% and is committed to growing its dividend supported by such earnings.

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

APCo's greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of organic growth opportunities within APCo's existing portfolio of renewable energy and thermal energy facilities. 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 involves building on APCo's expertise in the origination of greenfield renewable energy projects, building upon APCo's existing portfolio of assets for further growth, and capitalizing on opportunities that may emerge in the current turbulence of the capital markets.

Regulated Water Utilities: In 2009, APUC branded all of its utilities under the Liberty Water brand. Liberty Water is committed to being the leading utility provider of safe, high quality and reliable water and wastewater services while providing stable and predictable earnings from its utility operations. Liberty Water delivers long term shareholder value by profitably owning and operating investor owned water and wastewater utilities providing safe, reliable transportation and delivery of water and wastewater treatment in its service areas. It is also focused on delivering continued growth in earnings by identifying opportunities which accretively expand its business portfolio.

Regulated Electrical Utilities: APUC has announced its plan to establish a third distinct business subsidiary focused on the provision of local regulated electrical generation and distribution utilities within a new business subsidiary to be called Liberty Electric. In this regard APUC announced plans to co-acquire an electrical generation and regulated distribution utility through a strategic partnership with Emera Inc. ("Emera") (see "Electrical Distribution Utility Acquisition").

During fiscal 2009, APUC made monthly cash dividends/distributions to shareholders/unitholders of $0.02 per share/trust unit per month or $0.24 per share/trust unit per annum. This level of dividends/cash distributions allows for both an immediate return on investment for shareholders/unitholders and retention of sufficient cash within APUC to fund growth opportunities, debt repayment and mitigate the impact of volatility in foreign exchange rates. APUC strives to achieve its results within a moderate risk profile consistent with top-quartile North American power, utility, and infrastructure operations. Effective January 1, 2010, APUC changed to a quarterly dividend from a monthly dividend. As a result, APUC anticipates declaring a per share dividend for the first quarter of 2010 of $0.06, which is the equivalent of the current per share dividend of $0.02 per month. The first quarterly record date is expected to be March 31, 2010, with a payment date on or about April 15, 2010.

Major Highlights in 2009

Converted to a Corporation

During 2009 APUC completed its conversion from an income trust to a corporation. The conversion was completed through a series of transactions more fully described below.

On October 27, 2009 the Fund's unitholders exchanged 100% of the outstanding trust units of the Fund for a new class of common shares ("New Common Shares") of APUC (formerly Hydrogenics Corporation or Hydrogenics), an existing corporation. Immediately prior to this exchange (the "Unit Exchange Offer"), Hydrogenics, under a Plan of Arrangement, transferred all of its operations and substantially all of its assets and liabilities to New Hydrogenics. The pre-existing publicly traded shares of Hydrogenics were contemporaneously redeemed for shares of New Hydrogenics and thus the pre-existing publicly traded shares of Hydrogenics no longer exist.

The transaction resulted in the unitholders of the Fund holding their interest in the Fund as shareholders of APUC. Excluding shares issued under the CD Exchange Offer (as defined and described below), the number of common shares of APUC outstanding immediately after completion of the Unit Exchange Offer was exactly the same as the number of the Fund's trust units outstanding immediately before the Unit Exchange Offer.

The Unit Exchange Offer was accounted for as a change in business form using the continuity of interests method of accounting. Under this method of accounting, the transfer of the assets, liabilities and equity of the Fund are recorded at their net book values in the financial statements of APUC as at October 27, 2009, the effective date of the transaction. As a result, APUC is required to be accounted for as though it were a continuation of the Fund but with its capital reflecting the exchange of APUC shares for trust units. For the periods reported up to the effective date of the Unit Exchange Offer all payments to unitholders were in the form of trust unit distributions and after that date all payments to shareholders were in the form of dividends.

APUC paid New Hydrogenics $10,813 and has accrued an additional amount of $494 as a final closing adjustment. As a result of the Unit Exchange Offer, together with substantively enacted changes in tax rates in December 2009, APUC recognized a future income tax asset of $60,014 and a deferred credit in relation to this asset of $49,879 as at December 31, 2009. For accounting purposes the deferred credit is recorded as a credit to tax expense when the future tax assets are realized.

Also as a result of the completion of the Unit Exchange Offer, APUC recorded an increase to its recorded future tax liability. This adjustment reflects the tax impact of recording future tax assets and liabilities for temporary differences in APUC's flow-through entities that are reversing or settling prior to 2011 which were previously not recorded since prior to the transaction these temporary difference reversals were not expected to be taxed in APUC.

APUC expensed allocated transaction costs of $3,460 during 2009 in relation to the Unit Exchange Offer.

Internalized APUC Management

On December 21. 2009, the Board of Directors of APUC (the "Board") reached agreement with the shareholders of Algonquin Power Management Inc. (the "Manager" or "APMI") to internalize all management functions of the Fund which were provided by the Manager. APUC will acquire the interest previously held by the Manager in the management services agreement, subject to regulatory and shareholder approval, with consideration to be paid in the form of issuance of 1,158,748 APUC shares (the "Shares"). An independent advisor retained by the Board concluded that the consideration to be paid by APUC pursuant to the transaction is fair, from a financial point of view. The expense has been measured at $4,693 using a price for each share of $4.03, the adjusted closing market price on December 21 2009, the date the agreement was ratified.

Effective as of December 21, 2009, Mr. Ian Robertson assumed overall responsibility for APUC's operations as Chief Executive Officer and will be invited to join the Board. Mr. Robertson previously held the position of Executive Director, Business Development with the Fund. Mr. Chris Jarratt has joined the Strategy Development Committee where he is co-directing the development of strategy with APUC management and will be invited to join the Board in the role of Vice Chairman. Mr. David Kerr has been retained to provide transitional services to APUC.

In accordance with the policies of the Toronto Stock Exchange, approval of the issuance of the Shares will be sought from shareholders at the next annual general meeting. The beneficial interest in the Shares of those individuals who are continuing in management roles with APUC is intended to create and maintain alignment with the interests of APUC's shareholders.

Addressed Near Term Debt Maturities - Exchange of Convertible Debentures

During the second quarter of 2009, the Board of Trustees of the Fund also announced that, in conjunction with the Unit Exchange Offer, holders of the Fund's convertible debentures would be provided the opportunity to exchange their debentures for new debentures of APUC (the "CD Exchange Offer").

Contemporaneously with the Unit Exchange Offer on October 27, 2009, holders of the Fund's convertible debentures exchanged their convertible debentures for convertible debentures or common shares of APUC resulting in the Fund's debentureholders becoming debentureholders and shareholders of APUC and the maturity date of the Series 1 Debentures being extended from 2011 to 2014.

Pursuant to the CD Exchange Offer, $63,755 of the outstanding Series 1 Debentures were exchanged for Series 1A Debentures in a principal amount of $66,943, and $21,209 of the outstanding Series 1 Debentures were exchanged for 6,607,027 shares of APUC. In addition, all of the outstanding Series 2 Debentures were exchanged for Series 2A Debentures in a principal amount of $59,967. (See – **Shareholder's Equity and Convertible Debentures**).

Strengthened Balance Sheet - $75 Million Offering of Common Shares and Convertible Debentures

On December 2, 2009, APUC completed, on a bought deal basis, an offering of 5,980,000 common shares at $3.35 per common share for gross proceeds of $20,033 and an offering for $55,000 principal amount of 7% convertible unsecured subordinated debentures due June 30, 2017 (the "Series 3 Debentures"). The underwriters of the offering also exercised in full an over-allotment option to purchase an additional 897,000 common shares and $8,250 principal amount of Series 3 Debentures on the same terms. As a result of the closing of the main offering and the over-allotment option, APUC raised an aggregate of $82,606 in net proceeds after underwriting expenses and before additional issuance costs ($86,288 in gross proceeds).

The Series 3 Debentures bear interest at a rate of 7% per annum payable semi-annually in arrears on the last day of June and December in each year commencing on June 30, 2010, and will mature on June 30, 2017. The Series 3 Debentures will be convertible at the holder's option into common shares of APUC at a conversion price of $4.20 per common share (See – Shareholder's Equity and Convertible Debentures).

Expanded Regulated Utility Business - Electrical Distribution Utility Acquisition

On April 23, 2009, APUC announced that it plans to co-acquire an electrical generation and regulated distribution utility through a strategic partnership with Emera Inc. ("Emera"). APUC and Emera will each own 50% of the newly formed California Pacific Electric Company, LLC ("Calpeco"), a California limited liability company, which intends to acquire the California-based electricity distribution and related generation assets (the "California Utility") of NV Energy, Inc. for the purchase price of approximately US $116 million, subject to certain working capital and other closing adjustments. APUC and Emera will jointly own and operate the California Utility through Calpeco. The California Utility currently provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. In October 2009, an application was filed with the California Public Utilities Commission requesting approval of the transaction in which NV Energy has agreed to sell its California electric distribution and generation assets to Calpeco. The transaction is subject to state and federal regulatory approval which is expected to occur in the latter half of 2010.

As an element of the California Utility strategic partnership, Emera has also agreed to a conditional treasury subscription of approximately 8.5 million shares of APUC at a price of $3.25 per share. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of the California Utility.

As of December 31, 2009, APUC has incurred costs of $1.1 million related to the acquisition of the California Utility. These costs are recorded as deferred transaction costs in other assets on the Consolidated Balance Sheet.

Expanded Renewable Energy Portfolio – Tinker Hydro-electric Generating Asset Acquisition

Subsequent to December 31, 2009, on January 12, 2010, APUC completed the acquisition of 36.8 MW of electrical generating assets (the "Tinker Assets") that was announced on November 10, 2009. The Tinker Assets are located in New Brunswick and Maine and were purchased after satisfying the conditions of the acquisition, including regulatory approval.

Through the purchase of shares and assets, APCo has acquired three hydroelectric generating stations, the 34.5MW Tinker Hydro, a 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, Caribou Hydro, a 0.9MW run-of-river hydroelectric generating facility located in Northern Maine and Squa Pan Hydro, a 1.4MW run-of-river hydroelectric generating facility located in Northern Maine.

APCo has also acquired five thermal generating facilities with a rated capacity of 40MW in Northern Maine and New Brunswick utilized for installed reserve capacity, not continuous generation, 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, New England ISO).

In connection with the acquisition of the Tinker Assets, on February 4, 2010, APCo acquired a number of load supply and energy procurement contracts in northern Maine and the Independent System Operator New England ("ISO-NE") market ("Energy Services Business"). It is anticipated that the majority of the energy sold by the Energy Services Business will be supplied through generation from the Tinker Assets, based on historical long term average levels of hydroelectric energy generation of these facilities. The Energy Services Business 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.

The Energy Services Business is based on a series of short-term energy supply agreements which generally will expire within the next 14 months. 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.

The hydroelectric and thermal generation assets offer capacity to support the energy services obligations in northern Maine. The acquisition improves hydrologic diversification through a new geographical area to the APCo generation portfolio and builds APCo's Eastern Canadian generating presence.

Improved Utility Customer Service – Developed Liberty Water Brand

During the 2009, the 18 individual water and waste water utilities owned by APUC were reorganized under the consolidated brand of Liberty Water with the objective of improving the quality and consistency of services provided to the organization's approximately 70,000 regulated water/wastewater utility customers through updated web customer service, paperless electronic billing and expanded service hours. A secondary objective of aggregating APUC's water utility operations under the Liberty Water brand is to support the transparent analysis of APUC's water utility business as compared to other publicly traded US based water utility businesses.

Improved Corporate Governance – Expanded Board

At the annual general meeting of unitholders of the Fund held on July 27, 2009, in addition to the re-election of existing trustees, Mr. Huskilson was elected as a trustee of the Fund. As part of the Unit Exchange Offer, the trustee's of the Fund also became directors of APUC. The Board and management of APUC believe that Mr. Huskilson's utility and power experience will make a strong addition to the Board and will support APUC's long term strategy and corporate governance activities. As part of the management internalization process, Mr. Robertson and Mr. Jarratt have been invited to join the Board.

APUC's slate of proposed Directors in respect of the election of Directors by shareholders at the annual general meeting shall continue to be determined by the Directors in accordance with APUC's governance policies and procedures. It is contemplated that Mr. Robertson and Mr. Jarratt will stand for election as Directors at the next annual general meeting of shareholders.

Annual consolidated results from operations

Key Selected Annual Financial Information

	Year ended December 31		
	2009	**2008**	**2007**
Revenue	**$ 187,265**	$213,796	$186,175
Adjusted EBITDA [2]	**$ 79,368**	$ 90,028	86,169
Cash provided by Operating Activities	**50,022**	77,223	40,427
Net earnings (loss)	**31,257**	(19,038)	24,763
Adjusted net earnings [2]	**30,503**	18,788	
Dividends/Distributions to Shareholders/Unitholders [1]	**19,322**	57,755	69,923
Per share/trust unit:			
Net earnings	**$ 0.39**	$ (0.25)	0.34
Adjusted net earnings [2]	**$ 0.38**	$ 0.25	
Diluted net earnings (loss)	**$ 0.39**	$ (0.25)	0.31
Cash provided by Operating Activities	**$ 0.63**	$ 1.03	0.55
Dividends/Distributions to Shareholders/Unitholders	**$ 0.24**	$ 0.75	0.92
Total Assets	**1,013,413**	978,515	954,067
Long Term Debt	**241,412**	293,590	281,725

[1] Includes dividends/distributions to APUC shareholders/unitholders and distributions to Airsource units exchangeable into Fund units.

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

For the year ended December 31, 2009, APUC reported total revenue of $187.3 million as compared to $213.8 million during the same period in 2008, a decrease of $26.5 million or 12.4%. The decrease in APUC revenue in the twelve months ended December 31, 2009 was primarily the result of $23.3 million in lower APCo revenue due to reduced average energy rates, lower demand for steam at the Sanger and Windsor Locks facilities in the Thermal Energy division, and $6.8 million lower revenue due to lower weighted average energy rates and lower average hydrology and wind resources in the Renewable Energy division, as compared to the same period in 2008. These decreases were partially offset by an increase of $2.5 million due to the Brampton Cogeneration Inc. ("BCI") facility being operational in the APCo Thermal Energy division as compared to the same period in 2008 as BCI commenced operations in June 2008. APUC reported increased revenue of $5.3 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008. A more detailed analysis of these factors is presented within the business unit analysis. APCo attributes the reduced average energy rates to the overall effect the economic slow down has had on energy prices primarily in New York and New England where its hydro electric plants sell merchant power. APCo attributes lower revenue at its Sanger and Windsor Locks facilities to lower gas prices and to lower demand from the steam hosts resulting from the recession in the U.S.

For the year ended December 31, 2009, APUC experienced an average U.S. exchange rate of approximately $1.142 as compared to $1.067 in the same period in 2008. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency. Although a weaker Canadian dollar relative to the U.S. dollar has an impact on both revenue and expenses generated by its U.S. subsidiaries, APUC's foreign exchange forward contracts partially offset the impact on earnings (see Risk Management).

Adjusted EBITDA in the twelve months ended December 31, 2009 totalled $79.4 million as compared to $90.0 million during the same period in 2008, a decrease of $10.7 million or 12%. The decrease in Adjusted EBITDA is primarily related to $8.8 million in lower earnings from operations primarily resulting from lower gas prices and reduced demand for steam in the APCo Thermal Energy division and lower average energy rates earned by the APCo Renewable Energy division's U.S. facilities. 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, 2009, net earnings totalled $31.3 million as compared to net loss of $19.0 million during the same period in 2008. Net earnings per share/trust unit totalled $0.39 for the year ended December 31, 2009, as compared to net loss per share/trust unit of $0.25 during the same period in 2008.

The increase in net earnings as compared to 2008 was primarily the result of a change in income of $65.5 million due to unrealized mark to market gains on derivative financial instruments partially offset by losses on derivative financial instruments contracts settled in the period, as a result of decreased interest rates and the weaker Canadian dollar.

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

	Year ended December 31		
	2009	2008	Change
Foreign Exchange Contracts:			
Unrealized mark to market loss/(gain) on derivative financial instruments	**$(15,682)**	$25,473	**$(41,155)**
Realized loss/(gain) on derivative financial instruments	**284**	(5,077)	**$ 5,361**
	$(15,398)	$20,396	**$(35,794)**
Interest Rate Swap Contracts:			
Unrealized mark to market loss/(gain) on derivative financial instruments	**$ (7,424)**	$16,953	**$(24,377)**
Realized loss/(gain) on derivative financial instruments	**5,504**	399	**$ 5,105**
	$ (1,920)	$17,352	**$(19,272)**
Derivative Financial Instruments Total:			
Unrealized mark to market loss/(gain) on derivative financial instruments	**$(23,106)**	$42,426	**$(65,532)**
Realized loss/(gain) on derivative financial instruments	**5,788**	(4,678)	**$ 10,466**
Total loss/(gain) on derivative financial instruments	**$(17,318)**	$37,748	**$(55,066)**

In addition, net earnings for the year ended December 31, 2009 increased $4.9 million from reduced interest expense due to lower rates on APUC's variable interest rate debt booked in the period, $5.3 million due to non-cash gains on foreign exchange resulting from the weaker Canadian dollar and $18.8 million related to a recovery in future income taxes primarily due to the conversion to a corporation from an income trust, changes in future income tax rates, tax losses on U.S. operations resulting from bonus depreciation and lower energy and natural gas prices as compared to the same period in 2008 and the recovery of non-deductible interest expense related to U.S. operations. These increases were partially offset by $6.5 million related to the write down of certain thermal assets, $4.7 million related to the costs associated with the internalization of management, $3.5 million related to corporatization costs, $2.0 million due to increased amortization expense, $8.8 million due to

lower earnings from operating facilities, $1.3 million due to increased administrative expenses and $5.9 million resulting from increased minority interest gains at the St. Leon facility primarily due to unrealized gains on financial instruments.

During the twelve months ended December 31, 2009, cash provided by operating activities totalled $50.0 million or $0.63 per share/trust unit as compared to cash provided by operating activities of $77.2 million, or $1.03 per share/trust unit during the same period in 2008. Cash provided by operating activities exceeded dividends/distributions by 2.6 times during the twelve months ended December 31, 2009 as compared to 1.4 times during the same period in 2008. The change in cash provided by operating activities after changes in working capital in the twelve months ended December 31, 2009 is primarily due to increased realized losses from derivative instruments and decreased earnings from operating facilities, as compared to the same period in 2008.

2009 Fourth quarter results from operations

Key Selected Quarterly Financial Information

	Three months ended December 31	
	2009	**2008**
Revenue	**$ 43,441**	$ 56,505
Adjusted EBITDA [2]	**$ 18,027**	$ 23,256
Cash provided by Operating Activities	**12,549**	24,752
Net earnings	**(1,366)**	(21,095)
Adjusted net earnings [2]	**11,504**	8,839
Dividend/distributions to Shareholders/Unitholders [1]	**4,998**	5,312
Per share/trust unit		
Net earnings	**$ (0.03)**	$ (0.28)
Adjusted net earnings [2]	**$ 0.14**	$ 0.12
Diluted net earnings	**$ (0.03)**	$ (0.28)
Cash provided by Operating Activities	**$ 0.15**	$ 0.32
Dividends/distributions to Shareholders/Unitholders	**$ 0.06**	$ 0.06
Total Assets	**1,013,413**	978,515
Long Term Debt	**241,412**	293,590

[1] Includes dividends/distributions to APUC shareholders/unitholders and Airsource units exchangeable into Fund units.

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

For the three months ended December 31, 2009, APUC reported total revenue of $43.4 million as compared to $56.5 million during the same period in 2008, a decrease of $13.1 million or 23%. The decrease in APUC revenue in the three months ended December 31, 2009 was primarily the result of a decrease of $4.1 million due to reduced average energy rates and lower demand for steam at the Sanger and Windsor Locks facilities in the APCo Thermal Energy division and a $2.8 million decrease due to lower weighted average energy rates and lower average hydrology and wind resources in the APCo Renewable Energy division, as compared to the same period in 2008. In addition, APUC reported decreased revenue of $4.4 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2008. A more detailed analysis of these factors is presented within the business unit analysis.

For the three months ended December 31, 2009, APUC experienced an average U.S. exchange rate of approximately $1.057 as compared to $1.212 in the same period in 2008. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency. Although a stronger Canadian dollar relative to the U.S. dollar has an impact on both revenue and expenses generated by its U.S. subsidiaries, APUC's foreign exchange forward contracts in place partially offset the impact on earnings (see Risk Management).

Adjusted EBITDA in the three months ended December 31, 2009 totalled $18.0 million as compared to $23.3 million during the same period in 2008, a decrease of $5.2 million or 22%. The decrease in Adjusted EBITDA is in part due to lower earnings from operations primarily resulting from lower gas prices and reduced demand for steam in the Thermal Energy division and lower average energy rates earned by the Renewable Energy division's U.S. facilities. 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, 2009, net loss totalled $1.4 million as compared to a net loss of $21.1 million during the same period in 2008. Net loss per share/trust unit totalled $0.03 for the three months ended December 31, 2009, as compared to net loss per share/trust unit of $0.28 during the same period in 2008.

The increase in net earnings as compared to 2008 was primarily the result of a change in income of $33.5 million due to unrealized mark to market gains on derivative financial instruments partially offset by losses on derivative financial instruments contracts settled in the period, as a result of increased interest rates and the stronger Canadian dollar.

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

	Three months ended December 31		
	2009	2008	Change
Foreign Exchange Contracts:			
Unrealized mark to market loss/(gain) on derivative financial instruments	**$(1,261)**	$17,583	**$(18,844)**
Realized loss/(gain) on derivative financial instruments	**(148)**	345	**$ (493)**
	$(1,409)	$17,928	**$(19,337)**
Interest Rate Swap Contracts:			
Unrealized mark to market loss/(gain) on derivative financial instruments	**$(1,627)**	$13,058	**$(14,685)**
Realized loss/(gain) on derivative financial instruments	**1,520**	139	**$ 1,381**
	$ (107)	$13,197	**$(13,304)**
Derivative Financial Instruments Total:			
Unrealized mark to market loss/(gain) on derivative financial instruments	**$(2,888)**	$30,641	**$(33,529)**
Realized loss/(gain) on derivative financial instruments	**1,372**	484	**$ 888**
Total loss/(gain) on derivative financial instruments	**$(1,516)**	$31,125	**$(32,641)**

In addition, net earnings for the three months ended December 31, 2009 increased by $6.7 million related to a recovery in future income taxes primarily due to the reasons outlined in the discussion of the annual results, above and $2.6 million due to non-cash gains resulting from the stronger Canadian dollar as compared to the same period in 2008. These items were partially offset by decreases of $1.1 million due to lower earnings on portfolio investments, $4.4 million due to lower earnings from operating facilities, $6.5 million related to the write down of certain thermal assets, $4.7 million related to the internalization of management, $3.5 million related to corporatization costs, $2.1 million resulting from increased minority interest gains at the St. Leon facility primarily due to unrealized gains on financial instruments and $0.2 million due to increased amortization expense as compared to the same period in 2008.

During the three months ended December 31, 2009, cash provided by operating activities totalled $12.5 million or $0.15 per share/trust unit as compared to cash provided by operating activities of $24.8 million, or $0.32 per share/trust unit during the same period in 2008. Cash provided by operating activities exceeded dividends/distributions by 2.4 times during the quarter ended December 31, 2009 as compared to 5.3 times during the same period in 2008. The change in cash provided by operating activities after changes in working capital in the three months ended December 31, 2009, is primarily due to increased realized losses from derivative instruments and decreased cash flow from operating facilities, as compared to the same period in 2008.

Outlook

APCo

APCo's Renewable Energy division is expected to perform at or below long term average resource conditions in the first quarter of 2010 with the exception of the Quebec and New England regions where APCo anticipates at or above long term average resource conditions. APCo is expecting an improvement in weighted average energy rates at its U.S. renewable facilities as compared to the rates experienced in the first quarter of 2009. The 2010 first quarter results will include results from the acquisition of three hydroelectric generating stations with a capacity of 36.8 MW located in New Brunswick and Maine. The energy produced by these facilities will be shown as the Maritime Region.

APCo Thermal Energy division's Energy-From-Waste ("EFW") facility is expected to operate below APCo's expectations during the first quarter of 2010 due to an unplanned outage in January 2010 related to problems with boiler and economizer tubes. The facility is expected to be operational in spring 2010 once the boiler and economizer tube issues are resolved. APCo is accelerating capital maintenance originally planned for the second and third quarters of 2010 during this outage which should allow the facility to make up some of the income expected to be lost in the first quarter in the remainder of 2010.

APCo Thermal Energy division's Sanger facility is expected to operate at or above APCo's expectations for the first quarter of 2010 in line with 2009 results. APCo's power development team will continue to pursue new opportunities for power generation projects in both Canada and the U.S. APCo will continue to focus on cost containment and productivity improvement measures that will maximize margins and EBITDA throughout 2010.

APCo Thermal Energy division's Windsor Locks facility is expected to operate at or above APCo's expectations for the first quarter of 2010 and in line with 2009 results. In the second quarter APCo expects Windsor Locks to perform in line with 2009 results until the power purchase agreement with Connecticut Light & Power ("CL&P") expires in April 2010 after which APCo expects to be able to sell between 10MW and 40MW of electrical capacity to a local utility or provide ancillary services such as "spinning reserves" to the ISO-NE. For a more detailed description of the options and expected impact see Development Division - Windsor Locks.

Liberty Water

Liberty Water has ongoing rate cases at a number of its utilities and will continue to process these rate cases throughout 2010. These rate cases are discussed in further detail within this MD&A (see Liberty Water: Outlook). An exact determination of increased revenues from all rate case applications is not possible at this time as the timing of conclusion to the rate cases and the final decision on rate increases are determined by the regulator. As a result of delays in the progress of rate cases through the regulatory processes, Liberty Water now anticipates that approximately $7 million of additional revenue from rate cases will be achieved in 2010 but the full annualized increase in revenues determined through the rate case processes is expected to be achieved in 2011.

The regulatory reviews of the rates and tariffs for these facilities are expected to conclude in early 2010, with the new rates and tariffs implemented and/or going into effect in the first half of 2010, depending on the state in which the relevant facility operates. The business unit will also continue to consider accretive water and wastewater utility acquisition opportunities, as well as acquisitions in other regulated utilities, such as electricity distribution.

With respect to growth, Liberty Water is expecting limited organic expansion due to the slowdown in the U.S. housing market. Liberty Water expects to deliver growth through the acquisition of an additional small utility system.



APCo: Renewable Energy

	Three months ended December 31		Twelve months ended December 31	
	2009	2008	2009	2008
Performance (MW-hrs sold)				
Quebec Region	**73,650**	78,720	**299,900**	320,025
Ontario Region	**32,775**	33,072	**141,825**	147,125
Manitoba Region	**89,625**	105,643	**364,500**	377,450
New England Region	**16,200**	21,066	**81,725**	84,950
New York Region	**24,750**	25,461	**95,000**	92,000
Western Region	**10,875**	12,790	**58,200**	69,050
Total	**247,875**	276,752	**1,041,150**	1,090,600
Revenue				
Energy sales	**$ 16,604**	$ 19,175	$ 68,227	$ 75,549
Expenses				
Operating expenses	**(6,619)**	(6,160)	(22,279)	(22,015)
Other income	**433**	507	1,226	1,477
Division operating profit (including other income)	**$ 10,418**	$ 13,522	$ 47,174	**$ 55,011**

As APCo's hydroelectric generating facilities in the New York and New England regions primarily sell their output at market rates, the average revenue earned per MW-hr sold can vary significantly from the same period in the prior year. APCo's facilities in the other regions are subject to varying rates, by facility, as set out in each facility's individual power purchase agreement ("PPA"). As such, while most of APCo's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities which 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.

2009 Annual Operating Results

For the year ended December 31, 2009 the Renewable Energy division produced 1,041,150 MW-hrs of electricity, as compared to 1,090,600 MW-hrs produced in the same period in 2008, a decrease of 4.5%. The production level in 2009, while slightly lower than the previous year still represents production levels above long term averages. The production in the twelve months ended December 31, 2009 represents sufficient renewable energy to supply the equivalent of 57,800 homes on an annualized basis with renewable power.

Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 575,000 tons of CO2 gas was prevented from entering the atmosphere in 2009.

For the year ended December 31, 2009, the division generated electricity equal to 102% of long term projected average resources (wind and hydrology) as compared to 107% during the same period in 2008. In 2009, a number of regions experienced resources at significantly higher levels than long term average, including the Quebec region which was 8% above long term averages, the New England region, which was 33% above long

term averages and the New York region, which was 9% above long term averages. Several regions experienced resources at or below long term averages, including the Western region which was 13% below long term average resources, the Ontario region which was 7% below long term average resources and the Manitoba region which was 2% below long term average resources.

For the year ended December 31, 2009, revenue from energy sales in the Renewable Energy division totalled $68.2 million, as compared to $75.5 million during the same period in 2008. Revenue from APCo's U.S. facilities decreased $4.0 million due to a decrease in weighted average energy rates of approximately 36% in the New England and New York regions, partially offset by an increase of $0.1 million due to higher than average hydrology, as compared to the same period in 2008. Revenue from APCo's Canadian hydroelectric facilities decreased $2.2 million due to lower average hydrology, partially offset by an increase of $0.3 million due to an increase in weighted average energy rates of approximately 0.9% and, as compared to the same period in 2008. Revenue from the Manitoba region decreased $0.8 million due to a weaker wind resource and $0.2 million due to a decrease in weighted average energy rates of approximately 0.7%, as compared to the same period in 2008. The division reported an increase in revenue of $0.4 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the year ended December 31, 2009, operating expenses totalled $22.2 million, as compared to $22.0 million during the same period in 2008, an increase of $0.2 million. Operating expenses were impacted by $0.4 million of increased repair and maintenance costs at the St. Leon facility resulting from scheduled payments under the extended warranty and operation and maintenance agreements with Vestas-Canadian Wind Technology Inc. ("Vestas"), increased operational and administrative expenses of $0.3 million, an increase of $0.2 million resulting from increased Canadian property taxes, an increase of $0.2 million resulting from increased repair and maintenance expenses incurred on Canadian facilities, partially offset by decreased variable operating costs of $0.9 million tied to lower revenue associated with U.S. facilities as compared to the same period in 2008. Operating expenses include costs of $2.1 million associated with the pursuit of various growth and development activities, a reduction of $0.2 million as compared to the same period in 2008. The division reported increased expenses of $0.5 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the year ended December 31, 2009, Renewable Energy's operating profit totalled $47.2 million, as compared to $55.0 million during the same period of 2008, representing a decrease of 14.2%. For the year ended December 31, 2009, Renewable Energy's operating profit did not meet APCo's expectations primarily due to lower than expected weighted average energy rates in the U.S.

2009 Fourth Quarter Operating Results

For the quarter ended December 31, 2009 the Renewable Energy division produced 247,875 MW-hrs of electricity, as compared to 222,700 MW-hrs produced in the same period in 2008, an increase of 11.3%. The level of production in 2009 represents sufficient renewable energy to supply the equivalent of 55,100 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 138,000 tons of CO_2 gas was prevented from entering the atmosphere in the fourth quarter of 2009.

During the quarter ended December 31, 2009, the division generated electricity equal to 93% of long term projected average resources (wind and hydrology) as compared to 105% during the same period in 2008. A number of regions experienced resources at significantly higher levels than long term averages, including the New York region, which was 8% above long term averages and the New England region, which was 16% above long term averages. The Western region experienced results 18% below long term average resources, the Manitoba region experienced results 16% below long term averages, and the Ontario region experienced results 15% below long term averages in the quarter ended December 31, 2009.

For the quarter ended December 31, 2009, revenue from energy sales in the Renewable Energy division totalled $16.6 million, as compared to $19.2 million during the same period in 2008. Revenue from APCo's U.S. facilities decreased $0.3 million due to a decrease in weighted average energy rates of approximately 17% in the New England region and $0.3 million due to decreased average hydrology, as compared to the same period in 2008. Revenue from the Manitoba region increased $0.1 million due to an increase in weighted average energy rates of approximately 1.3%, offset by a decrease of $1.0 million due to a weaker wind resource, as compared to the same period in 2008. Revenue from APCo's Canadian facilities decreased $0.7 million due to lower energy production, partially offset by $0.4 million due to an increase in weighted average energy rates as compared to the same period in 2008. The division reported decreased revenue of $0.5 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2008.

For the quarter ended December 31, 2009, operating expenses totalled $6.6 million, as compared to $6.2 million during the same period in 2008, a decrease of $0.4 million. Operating expenses were impacted by $0.3 million of increased expenses at the St. Leon facility, primarily resulting from scheduled payments under the extended warranty and operation and maintenance agreements with Vestas, increased operational and administrative expenses of $0.2 million, $0.1 million resulting from increased U.S. property taxes, partially offset by decreased variable operating costs of $0.1 million tied to lower revenue associated with U.S. facilities, as compared to the same period in 2008. Operating expenses include costs of $0.9 million associated with the pursuit of various growth and development activities, as compared to $0.8 million in the same period in 2008. The division reported decreased expenses of $0.3 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2008.

For the quarter ended December 31, 2009, Renewable Energy's operating profit totalled $10.4 million, as compared to $13.5 million during the same period of 2008, representing a decrease of 23.0%. For the quarter ended December 31, 2009, Renewable Energy's operating profit did not meet APCo's expectations primarily due to lower than expected weighted average energy rates in the U.S. and a lower wind resource.

Divisional Outlook – Renewable Energy

The APCo Renewable Energy division is expected to perform at or below long term average resource conditions in the first quarter of 2010 with the exception of the Quebec and New England regions where APCo anticipates at or above long term average resource conditions.

On January 12, 2010, APCo completed the acquisition of three hydroelectric generating stations located in New Brunswick and Maine with installed capacity of 36.8MW, which include, most notably, the 34.5MW Tinker Hydroelectric station located on the Aroostook River near the Town of Perth-Andover, New Brunswick. The energy produced by these facilities will be shown as the Maritime Region in the first quarter of 2010.

In connection with the Tinker acquisition which closed January 12, 2010, on February 4, 2010, APUC acquired the Energy Services Business which provides energy to commercial and industrial customers in the northern Maine and New Brunswick markets. The Energy Services Business anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 150,000 MW-hrs of energy to its customers at an average rate of $80/MW-hr on an annualized basis. Based on historical long term average levels of hydroelectric energy generation, the Tinker Assets are anticipated to provide greater than 80% of the energy required by the Energy Services Business to service its customers which provide a natural hedge on supply costs of the Energy Services Business.

In addition to the energy generation provided by the Tinker Assets, the Energy Services Business anticipates buying additional energy on the open market in order to services its customer demand. APCo manages the risk associated with this business through internally generated energy from the Tinker Assets, as well as, through the purchase of fixed volume/prices from the ISO NE market. In addition, APCO 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.

As a result of certain legislation passed in Quebec (Bill C93), APCo's Renewable Energy division is required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased within the Province of Quebec. In the first quarter of 2010 APCo expects to complete the required assessments necessary to determine the work required and estimate capital cost of compliance with the legislation. APCo is required to submit plans for undertaking any remedial measures that are identified to comply with the legislation. As a result of nine completed and two partially completed assessments, APCo has estimated capital expenditures of approximately $17.5 million related to compliance with the legislation. The timing of when the actual capital costs need to be made is determined as part of the technical assessments.

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

	Total	2010	2011	2012	2013	2014
Estimated Bill C-93 Capital Expenditures	**17,500**	5,000	6,000	1,200	2,800	2,500

The majority of these capital costs are associated with the Donnacona, St. Alban and Mont-Laurier facilities. APCo does not anticipate any significant impact on power generation or associated revenue while the dam safety work is ongoing. APCo continues to explore several alternatives to mitigate the capital costs of the modifications, including cost sharing with other stakeholders and revenue enhancements which can be achieved through the modifications.

APCo: Thermal Energy Division

	Three months ended December 31		Twelve months ended December 31	
	2009	2008	2009	2008
Performance (MW-hrs sold)	**147,482**	145,050	**571,505**	597,923
Performance (tonnes of waste processed)	**42,189**	42,348	**161,102**	161,198
Revenue				
Energy sales	**$ 13,819**	$ 21,806	**$ 62,209**	$ 82,959
Less:				
Cost of Sales – Fuel *	**(5,224)**	(11,597)	**(26,517)**	(44,706)
Net Energy Sales Revenue	**$ 8,595**	$ 10,209	**$ 35,692**	$ 38,253
Waste disposal sales	**3,786**	3,998	**14,468**	15,706
Other revenue	**545**	1,691	**3,848**	4,349
Total net revenue	**$ 12,926**	$ 15,898	**$ 54,008**	$ 58,308
Expenses				
Operating expenses *	**(7,121)**	(8,807)	**(30,782)**	(32,515)
Interest and other income	**872**	868	**3,749**	3,665
Division operating profit (including interest and dividend income)	**$ 6,677**	$ 7,738	**$ 26,975**	$ 31,053

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

2009 Annual Operating Results

In 2009, the EFW facility processed 161,102 tonnes of municipal solid waste as compared to 161,198 tonnes processed in the same period of 2008. This level of production resulted in the diversion of approximately 117,600 tonnes of waste from landfill sites in 2009.

During the twelve months ended December 31, 2009, the business unit produced 571,505 MW-hrs of energy as compared to 597,923 MW-hrs of energy in the comparable period of 2008, a decrease of 4.4%. The business unit's performance decreased by 4,300 MW-hrs at the Sanger facility resulting from power curtailment by Pacific Gas and Electric Company ("PG&E") due to line loading issues on the utility side and 7,500 MW-hrs at the Windsor Locks facility due to reduced demand for steam from its steam host customer, as compared to the same period in 2008. The overall decrease in energy production at the EFW facility is due to steam generated

by the incineration process at the facility now being utilized by BCI for steam sales to a nearby industrial customer rather than being used to generate electricity. During the twelve months ended December 31, 2009, the business unit's BCI steam sales facility was operating for the full period having reached commercial operation in June 2008. Although this has resulted in the decrease in electrical generation from EFW's steam turbine of 16,300 MW-hrs, the decrease was more than offset by the new steam sales by BCI. Throughput at the EFW facility remained consistent with the same period in 2008.

For the year ended December 31, 2009, gross revenue in the Thermal Energy division totalled $80.5 million, as compared to $103.0 million during the same period in 2008, a decrease of $22.5 million. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. During the year ended December 31, 2009, net energy sales revenue at the Thermal Energy division totalled $35.7 million, as compared to $38.3 million during the same period in 2008, a decrease of $2.6 million. The decrease in revenue from net energy sales, as compared to the first twelve months of 2008, was primarily due to the Sanger facility experiencing a decrease of $5.6 million as a result of decreased energy rates, in part due to lower natural gas prices, and $0.7 million as a result of decreased production and decreased revenue at the Windsor Locks facility of $16.1 million as a result of lower energy rates, in part due to lower natural gas prices, and $0.9 million as a result of decreased demand for steam production as compared to the same period in 2008. The offsetting reduction in natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. In addition, revenue decreased $1.1 million at the landfill-gas ("LFG") facilities primarily as a result of lower energy rates and $1.0 million at the EFW facility as a result of a portion of the steam generated by the incineration process being used by BCI instead of being used to generate electricity. These decreases were partially offset by an increase of $2.5 million as a result of the BCI steam sales facility achieving commercial operation in June 2008, as compared to the same period in 2008. The division reported increased revenue of $2.2 million from operations as a result of the weaker Canadian dollar, as compared to the same period in 2008.

Revenue from waste disposal sales for the year ended December 31, 2009 totalled $14.5 million, as compared to $15.7 million during the same period in 2008, a decrease of $1.2 million. The facility earned lower average rates for each tonne of waste processed in the quarter, primarily the result of the arrangement to process higher priced airline waste at the facility ceasing in December 2008.

For the year ended December 31, 2009, fuel costs at Sanger and Windsor Locks totalled $26.5 million, as compared to $44.7 million during the same period in 2008, a decrease of $18.2 million. Natural gas expense at Sanger decreased $4.9 million (52%), primarily the result of a 50% decrease in the average price for natural gas as compared to the same period in 2008. In addition, production decreased 3%, primarily as a result of production curtailments by PG&E, decreasing the volume of natural gas used in ongoing operation of the facility as compared to the same period in 2008. Natural gas expense at the Windsor Locks facility decreased $14.2 million (44%), primarily the result of a 44% decrease in the average price for natural gas as compared to the same period in 2008. The division reported increased fuel costs of $0.9 million as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the year ended December 31, 2009, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $30.8 million, as compared to $32.5 million in the same period in 2008. Operating expenses for the period were impacted by decreased operating expenses of $0.6 million at the EFW facility primarily as a result of lower natural gas expenses and repair and maintenance expenses, $0.5 million at the hydro-mulch facility primarily resulting from reduced repair and maintenance costs and $0.5 million primarily due to decreased repair and maintenance costs at the Valley Power facility, as compared to the prior period. Expenses at the LFG facilities decreased $2.2 million due to lower operating, royalty, repair, maintenance and natural gas expenses as compared to the same period in 2008. In 2008 expenses at the LFG facilities included $0.6 million of costs associated with its investment in the landfill gas tax credit program which did not occur in 2009. These decreases were partially offset by increased expenses at the Windsor Locks facility primarily due to $0.4 million in costs associated with compliance with the greenhouse gas initiatives and $0.7 million of operating costs of the BCI steam facility as compared to the same period in 2008. The reported operating costs at the BCI facility exclude the cost of purchasing steam from the EFW facility as this is eliminated upon consolidation. The division reported increased operating expenses of $0.7 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the year ended December 31, 2009, the Thermal Energy division's operating profit totalled $27.0 million, as compared to $31.1 million during the same period in 2008, a decrease of $4.1 million or 13.1%. Operating profit in the Thermal Energy division did not meet overall expectations for 2009, due to weaker gas prices and lower demand for steam from the division's co-generation assets resulting from the current economic slow down in the U.S.

2009 Fourth Quarter Operating Results

In the fourth quarter of 2009, the EFW facility processed 42,189 tonnes of municipal solid waste as compared to 42,348 tonnes processed in the same period of 2008, a decrease of 0.4%. This level of production resulted in the diversion of approximately 30,700 tonnes of waste from landfill sites in the fourth quarter of 2009.

During the quarter ended December 31, 2009, the business unit produced 147,482 MW-hrs of energy as compared to 145,050 MW-hrs of energy in the comparable period of 2008. During the quarter ended December 31, 2009, the business unit's performance increased by 700 MW-hrs at the Windsor Locks facility, 2,100 MW-hrs at the Sanger facility and 1,500 MW-hrs at the Valley Power facility as compared to the same period in 2008. During the quarter ended December 31, 2009, the BCI steam facility used more EFW steam in its operations, resulting in a decrease in electrical generation from EFW's steam turbine of 1,000 MW-hrs. Throughput at the EFW facility was consistent with the same period in 2008.

For the quarter ended December 31, 2009, revenue in the Thermal Energy division totalled $18.2 million, as compared to $27.5 million during the same period in 2008, a decrease of $9.3 million. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the quarter ended December 31, 2009, net energy sales revenue at the Thermal Energy division totalled $8.6 million, as compared to $10.2 million during the same period in 2008, a decrease of $1.6 million. The decrease in revenue from energy sales was primarily due to a decrease of $0.7 million at the Sanger facility as a result of decreased energy rates, in part due to lower natural gas prices, partially offset by $0.3 million as a result of increased production, and a decrease of $4.8 million at the Windsor Locks facility as a result of decreased energy rates, in part due to lower natural gas prices, partially offset by $0.1 million as a result of increased demand for steam production, as compared to the same period in 2008. The offsetting reduction in natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased revenue of $2.7 million from operations as a result of the stronger Canadian dollar, as compared to the same period of 2008.

Revenue from waste disposal sales for the quarter ended December 31, 2009 totalled $3.8 million, as compared to $3.9 million during the same period in 2008. The facility earned lower average rates for each tonne of waste processed in the quarter, primarily the result of the arrangement to process higher priced airline waste at the facility ceasing in December 2008.

For the quarter ended December 31, 2009, fuel costs at Sanger and Windsor Locks totalled $5.2 million, as compared to $11.6 million during the same period in 2008, a decrease of $6.4 million. Natural gas expense at Sanger decreased $0.3 million (18%), primarily the result of a 22% decrease in the average price for natural gas as compared to the same period in 2008. Natural gas expense at the Windsor Locks facility decreased $4.4 million (55%), primarily the result of a 56% decrease in the average price for natural gas as compared to the same period in 2008. The division reported decreased fuel costs of $1.7 million as a result of the stronger Canadian dollar as compared to the same period in 2008.

For the quarter ended December 31, 2009, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $7.1 million, as compared to $8.8 million during the same period in 2008, a decrease of $1.7 million. The decrease in operating expenses for the quarter was primarily due to reduced operating costs of $0.5

million at the LFG facilities resulting from lower repair, maintenance, royalty and operating expenses, $0.2 million at BCI resulting from lower natural gas expenses and $0.3 million in lower consumables and repair and maintenance expenses at the hydro-mulch facility as compared to the same period in 2008. The division reported decreased operating expenses of $0.6 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2008.

For the quarter ended December 31, 2009, the Thermal Energy division's operating profit totalled $6.7 million, as compared to $7.7 million during the same period in 2008, representing a decrease of 13.0%. Operating profit in the Thermal Energy division did not meet overall expectations for the quarter ended December 31, 2009, due to weaker gas prices and lower demand for steam from the Division's co-generation assets resulting from the current economic slow down in the U.S.

Divisional Outlook – Thermal Energy

The EFW facility is expected to operate below expectations during the first quarter of 2010 due to an unplanned outage in late January 2010 due to a failure with boiler and economizer tubes, some of which were scheduled for replacement as part of the current year capital expenditure plan. APCo intends to accelerate this replacement and simultaneously advance capital maintenance originally planned for the second and third quarters of 2010 during the outage which should allow the facility to make up some of the income expected to be lost in the first quarter in the remainder of 2010. APCo estimates the outage will negatively impact operating profit from EFW in 2010 by approximately $1.2 million compared to its operating profit in 2009.

The Thermal Energy division's Sanger facility is expected to operate at or above expectations for the first quarter of 2010 in line with 2009 results.

Windsor Locks is expected to operate at or above APCo's expectations for the first quarter of 2010 and in line with 2009 results. In the second quarter APCo expects Windsor Locks to perform in line with 2009 results until the power purchase agreement with Connecticut Light & Power ("CL&P") expires in April 2010 after which APCo expects to be able to sell between 10MW and 40MW of electrical capacity to a local utility or provide ancillary services such as "spinning reserves" to the ISO-NE. For a more detailed description of the options and expected impact see Development Division - Windsor Locks.

APCo: Development Division

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

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

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

Current Development Projects

Red Lily

APCo continues to advance the Red Lily Wind Project in south-eastern Saskatchewan (the "Project" or "Red Lily"). In July 2008, a 25 MW PPA for the first phase of the Project ("Phase I") was executed with SaskPower after Phase I was successfully bid into a SaskPower Environmentally Preferred Power Strategy Request for Proposal. In June 2009, APCo and Natural Resources Canada ("NRC") executed a Contribution Agreement under the ecoENERGY for Renewable Power Program for Phase I, securing funding for the project in advance of the expectation of the program being fully subscribed later in 2009. APCo has submitted to NRC the Environmental Impact Assessment documentation for review in relation to obtaining funding under the federal ecoENERGY program and is following up with NRC, as the lead agency, on comments received from other agencies. Notably, on April 13, 2009 Saskatchewan Environmental Assessment Branch confirmed that APCo had satisfied the requirements under the Provincial Environmental Assessment Act for Phase I. APCo is currently awaiting confirmation of a development permit from the regional municipality of Martin.

APCo is considering a number of financing alternatives for Red Lily. Currently, the most likely alternative will see the Project financed through an equity injection from a third party together with APCo's participation arising in the Project solely through a subordinated debt commitment of up to $19.0 million. APCo would retain responsibility and receive fees in respect of the development, construction, operation and supervision of the Project. After 5 years, APCo would have an option to subscribe for a 75% equity interest in the Project in exchange for its subordinated debt commitment.

On behalf of Red Lily, APCo is in the process of finalizing the contracts necessary to construct the project and has executed term sheets to secure all of the required financing, with the anticipation that the funding will be available in the first quarter of 2010. The earliest expected commissioning date of the project is December 31, 2010. In addition to the focused effort on Phase I, APCo has secured additional property and is assessing the viability of an expanded project. The viability of the expanded project will be conditional upon actual operating results from Phase I.

Successful development of wind projects such as Red Lily are subject to significant risks and uncertainties including the ability to obtain financing on acceptable terms within deadlines imposed by the utility, reaching agreement with any other external parties involved in the project, currency fluctuations affecting the cost of major capital components such as wind turbines, price escalation for construction labour and other construction inputs and construction risk that the project is built without mechanical defects and is completed on time and within budget estimates. Assuming the Project is developed, it is currently estimated to require 16 turbines with a capital investment of approximately $65 million. Annual energy production from the wind farm is estimated to be 88,100 MW-hrs and annual gross revenue is estimated to be $8.5 million.

Windsor Locks

The Windsor Locks facility is a 54MW natural gas power generating station located in Windsor Locks, Connecticut. The facility was acquired in 2003 and currently has an outstanding net book value to APCo of approximately US$17.2 million. The facility has two key energy agreements. The first agreement is the PPA with CL&P which expires in April 2010. The second agreement is the Energy Services Agreement ("ESA") with Ahlstrom Windsor Locks, LLC ("Ahlstrom"), a leading paper and non woven materials manufacturer, which, if not further extended by mutual agreement, will continue until 2017. The expiration of the CL&P PPA will impact operations beyond April 2010.

Commencing in April 2010, APCo will maximize net revenue by serving the steam and power requirements of Ahlstrom pursuant to the ESA together with bidding the remaining available capacity of approximately 40 MW into the thirty minute forward operating reserve market ("TMOR"). APCo has entered into an agreement with Emera Energy Services Inc. to manage the off-take sales from this facility into the ISO NE market.

APCo is continuing the preliminary engineering and environmental permitting work for the installation of a new combustion gas turbine more appropriately sized to meet the electrical and steam requirements of Ahlstrom. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to US $450/KW to a maximum of US $6.6 million to offset the cost of such re-powering. In addition to installing the new gas turbine, APCo would expect to continue to operate and maintain the existing equipment. Any investment in new capital for this site will be based on an assessment of the incremental earnings against such additional investment.

The Development division currently anticipates operating cash flow at the Windsor Locks facility for 2010 to be approximately U.S. $4.5 million compared to a historical cash flow of approximately U.S. $8.0 million. This operating cash flow estimate assumes participation in the summer 2010 and the winter 2010/2011 forward reserve auctions. TMOR has cleared at US $14 per MW month for the last 7 forward reserve procurement periods (two periods annually). During 2010, it is expected that APCo will earn revenue from steam and electrical sales to Ahlstrom, steam and electrical capacity payments made by Ahlstrom, energy sales to ISO-NE, capacity payments made by ISO-NE and TMOR payments made by ISO-NE. Under this operating protocol APCo will need to acquire 750,000MMBTU to 835,000MMBTU of natural gas annually in addition to the natural gas purchases reimbursed by Ahlstrom.

Other

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

Future Development Projects – Greenfield Projects

There are a number of future greenfield development projects which are being actively pursued by the Development division. These projects encompass several new wind energy projects having a potential generation capacity of over 250 MW, hydroelectric projects at different stages of investigation, and thermal energy generation projects. The projects being examined are located both in Canada and the United States.

In addition to the second phase of the Red Lily project, APCo is currently collecting wind data on three other sites in Saskatchewan and expects to respond to the Provinces' Request for Qualifications to procure up to 175MW of wind power from one or more independent power producers.

APCo owns the rights, including land options, meteorological towers and historical wind data related to a potential 80 MW Canadian wind project. In the event the project is developed, it is currently estimated to require an investment of up to $250 million and is expected to require 2 to 3 years to complete.

In 2008, APCo made a strategic decision to maintain land option agreements for two wind projects in Quebec in anticipation of future provincial tenders. In May 2009, Hydro Quebec released details in relation to a tender request for wind projects of a 25 MW maximum size. In addition, APCo has developed a relationship with two development co-operatives comprised of landowners and other small investors for the potential development of a third and fourth project in response to the expected call for tender. Algonquin will assess the economics of these projects individually and will bid into the RFP accordingly.

Discussions with the Ontario Power Authority indicate that energy procurement initiatives will be positively influenced by the Green Energy Act ("GEA") which received Royal Assent on May 14, 2009. The GEA is intended to provide the catalyst for the development of 50,000 new green economy jobs and is viewed by APCo as positive for the development of renewable energy in Ontario. The Development division is maintaining relationships with potential partners for the development of a number of projects that could qualify under anticipated procurement initiatives undertaken by the Ontario Power Authority in accordance with the GEA. In addition, APCo has applied to become applicant of record for three crown land sites under the Ministry of Natural Resources wind power site release programme, and has recently submitted 42 MW of on-shore wind energy projects in eastern Ontario under the GEA's Feed-in Tariff program ("FIT"). The on-shore wind price set by the FIT program is $0.135 per kWH.

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

Future Development Projects – Existing Facilities

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

Renewable Energy

The St. Leon Wind Project achieved commercial operation status under its PPA with the Manitoba Hydro Electric Board in June 2006, and has been performing at or above expected levels of production. APCo is exploring multiple options to continue to build on the success of this project including pursuing a future adjacent project and/or pursuing an increase in the installed capacity of the existing facility. The projects being reviewed have a potential generation capacity of over 85 MW. In the event these projects are developed, it is currently estimated to require an investment of approximately $250 million.

Thermal Energy

The EFW facility in the Thermal Energy division of APCo is designed to incinerate over 500 tonnes per day of municipal solid waste from the Region of Peel to produce steam that is used in the production of electricity and to supply the internal steam load for a nearby recycled paper board manufacturing mill. APCo established BCI to operate the required facilities to supply steam to the nearby paper board customer and pursue additional steam load customers.

The Development division is currently reviewing several proposals at the EFW facility to expand its power generation and waste processing throughput capacity. Throughput capacity could be expanded by between 40,000 and 100,000 tonnes annually depending on the proposal that is selected. If the expansion is pursued, depending on the alternative chosen, an investment of between $60 million to $250 million would be required. APCo is currently evaluating the feasibility of an expanded facility including associated capital and operating costs and financing terms. APCo is also engaged in discussions with the Region of Peel to establish a new long term contract for a reliable supply of municipal solid waste.

Divisional Outlook – Development

APCo 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. In the past year the Ontario government passed the Green Energy Act. Accordingly the Ontario Power Authority has issued standard pricing for electricity from renewable sources under a Feed-in Tariff. Included within this legislation is the requirement for Ontario Power Authority to purchase power generated from green energy projects, and an obligation for all utilities to grant priority grid access to such projects. The intention of the legislation is to make development of renewable energy projects significantly easier than the prior process of formal bids in response to requests for proposals from the responsible power authority.



LIBERTY WATER

	Three months ended December 31		Twelve months ended December 31	
	2009	2008	2009	2008
Number of				
Wastewater connections	**34,441**	34,190	**34,441**	34,190
Wastewater treated (millions of gallons)	**500**	450	**1,925**	1,850
Water distribution connections	**36,919**	36,297	**36,919**	36,297
Water sold (millions of gallons)	**1,400**	1,400	**5,900**	5,750
Assets for regulatory purposes (U.S. $)	**147,767**	149,295	**147,767**	149,295
Revenue				
Wastewater treatment	**$ 4,872**	$ 5,393	**$ 20,809**	$ 19,120
Water distribution	**3,719**	4,336	**17,179**	15,609
Other Revenue	**96**	107	**525**	504
	$ 8,687	$ 9,836	**$ 38,513**	$ 35,233
Expenses				
Operating expenses	(4,976)	(6,041)	(23,158)	(21,243)
Other income	(43)	55	1,368	102
Business Unit operating profit (including other income)	$ 3,668	$ 3,850	$ 16,723	$ 14,092

In 2009, Utility Services branded all of its utilities under the Liberty Water brand. Liberty Water is committed to being the leading utility provider of safe, high quality and reliable water and wastewater services while providing stable and predictable earnings from its utility operations.

Liberty Water reports total connections, inclusive of vacant connections rather than customers. Liberty Water had 34,441 wastewater connections as at December 31, 2009, as compared to 34,190 as at December 31, 2008, an increase of 251 year over year or 0.7%. Liberty Water had 36,919 water distribution connections as at December 31, 2009, as compared to 36,297 as at December 31, 2008, representing a year over year increase of 622 or 1.7%. Total connections include approximately 2,025 vacant wastewater connections and 1,475 vacant water distributions connections. Liberty Water's marginal change in water distribution and wastewater treatment customer base during the period continues to primarily relate to limited organic growth at Liberty Water's facilities resulting from the slow down in U.S. new residential home sales in areas served by the division.

Liberty Water has investments in regulatory assets of U.S. $147.8 million across four States as at December 31, 2009, as compared to U.S. $149.3 million as at December 31, 2008 and has active proceedings in Texas and Arizona to allow it to earn its full regulatory return on its investment in regulatory assets.

2009 Annual Operating Results

During the twelve months ended December 31, 2009, Liberty Water provided approximately 5.9 billion U.S. gallons of water to its customers, treated approximately 1.9 billion U.S. gallons of waste-water and sold approximately 475 million U.S. gallons of treated effluent.

For the year ended December 31, 2009, Liberty Water's revenue totalled $38.5 million as compared to $35.2 million during the same period in 2008, an increase of $3.3 million. Revenue from wastewater treatment totalled $20.8 million, as compared to $19.1 million during the same period in 2008, an increase of $1.7 million. Revenue from water distribution totalled $17.2 million, as compared to $15.6 million during the same period in 2008, an increase of $1.6 million. Liberty Water reported increased revenue from operations of $2.7 million in the year ended December 31, 2009 as a result of the weaker Canadian dollar as compared to the same period in 2008. Excluding the impact of foreign exchange, revenue increased U.S. $0.6 million or 1.8% as compared to the same period in 2008.

The twelve month water distribution revenue was impacted by increased revenue of $0.2 million at the four Texas Silverleaf facilities primarily due to the ongoing rate cases and the related implementation of interim rate increases, in conjunction with increased customer demand and limited organic growth, $0.2 million at the Litchfield Park facility ("LPSCo") primarily due to higher commercial water sales, and $0.2 million due to organic growth and increased customer demand at 9 water distribution facilities as compared to the same period in 2008. Liberty Water reported increased water distribution revenue of $1.2 million in the twelve months ended December 31, 2009 as a result of the weaker Canadian dollar as compared to the same period in 2008.

The twelve month wastewater treatment revenue was impacted by increased revenue of $0.4 million at the four Texas Silverleaf facilities and the Tall Timbers facility, primarily due to the ongoing rate cases and the related implementation of interim rate increases in conjunction with increased customer demand and limited organic growth, $0.4 million at LPSCo primarily due to higher treated effluent revenue as compared to the same period in 2008. These increases were partially offset by decreased wastewater treatment revenue of $0.4 million primarily resulting from a regulator imposed reduction in rates at the Gold Canyon facility and a decrease of $0.1 million due to decreased demand at the Rio Rico facility as compared to the same period in 2008. Liberty Water reported increased wastewater treatment revenue of $1.4 million in the twelve months ended December 31, 2009 as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the year ended December 31, 2009, operating expenses totalled $23.2 million, as compared to $21.2 million during the same period in 2008. Liberty Water reported higher expenses from operations of $1.7 million as a result of the weaker Canadian dollar, as compared to the same period in 2008. Excluding the impact of foreign exchange, overall expenses increased U.S. $0.5 million or 2.3% as compared to the same period in 2008.

Operating expenses increased $0.6 million as a result of increased wages, salary and other operating costs, $0.3 million in reduced contracted service expenses, $0.2 million in reduced transportation costs, $0.2 million in reduced utilities and consumables and $0.2 million in decreased repair and maintenance costs as compared to the same period in 2008.

For the year ended December 31, 2009, Liberty Water earned other income of $1.4 million on the disposition of non-utility assets with a book value of $1.1 million. During the comparable period in 2008, Liberty Water did not dispose of any significant other assets.

For the year ended December 31, 2009, Liberty Water's operating profit totalled $16.7 million as compared to $14.1 million during the same period in 2008. Excluding the gain on disposition of other assets, operating profits increased by 9.0%. Liberty Water' operating profit exceeded expectations for the year ended December 31, 2009.

2009 Fourth Quarter Operating Results

During the quarter ended December 31, 2009, Liberty Water provided approximately 1.4 billion U.S. gallons of water to its customers, treated approximately 500 million U.S. gallons of wastewater and sold approximately 100 million U.S. gallons of treated effluent.

For the quarter ended December 31, 2009, Liberty Water's revenue totalled $8.7 million as compared to $9.8 million during the same period in 2008, a decrease of $1.1 million. Revenue from wastewater treatment totalled $4.9 million, as compared to $5.4 million during the same period in 2008, a decrease of $0.5 million. Revenue from water distribution totalled $3.7 million, as compared to $4.3 million during the same period in 2008, a decrease of $0.6 million. Liberty Water reported decreased revenue from operations of $1.2 million in the fourth quarter of 2009 as a result of the stronger Canadian dollar as compared to the same period in 2008. Excluding the impact of foreign exchange, revenue was consistent with the same period in 2008.

The fourth quarter water distribution revenue was impacted by increased revenue of $0.1 million at the four Texas Silverleaf facilities primarily due to the ongoing rate cases and the related implementation of interim rate increases, offset by a decrease of $0.1 million at the Litchfield Park facility ("LPSCo") primarily due to lower commercial water sales and $0.1 million due to lower customer demand at 4 water distribution facilities as compared to the same period in 2008. Liberty Water reported decreased water distribution revenue of $0.5 million in the quarter ended December 31, 2009 as a result of the stronger Canadian dollar as compared to the same period in 2008.

The fourth quarter wastewater treatment revenue was impacted by increased revenue of $0.3 million at the four Texas Silverleaf facilities and the Tall Timbers facility, primarily due to the ongoing rate cases and the related implementation of interim rate increases, $0.1 million at LPSCo primarily due to higher treated effluent revenue as compared to the same period in 2008. These increases were partially offset by decreased wastewater treatment revenue $0.1 million primarily resulting from a regulator imposed reduction in rates at the Gold Canyon facility and $0.1 million due to lower customer demand at the Rio Rico facility as compared to the same period in 2008. Liberty Water reported decreased wastewater treatment revenue of $0.7 million in the twelve months ended December 31, 2009 as a result of the stronger Canadian dollar as compared to the same period in 2008.

For the quarter ended December 31, 2009, operating expenses totalled $5.0 million, as compared to $6.0 million during the same period in 2008. Liberty Water reported lower expenses from operations of $0.8 million as a result of the stronger Canadian dollar, as compared to the same period in 2008. Excluding the impact of foreign exchange, overall expenses decreased U.S. $0.3 million or 5.5% as compared to the same period in 2008.

Operating expenses decreased $0.1 million in reduced contracted services expenses, $0.1 million in reduced utilities and consumables expenses and $0.6 million as a result of the capitalization of rate case costs of multiple rate cases which were previously expensed due to the adoption of rate regulated accounting during the quarter, partially offset by an increase of $0.4 million as a result of increased wages, salary and other operating costs as compared to the same period in 2008.

For the quarter ended December 31, 2009, Liberty Water's operating profit totalled $3.7 million, comparable to the same period in 2008. Liberty Water's operating profit exceeded expectations for the three months ended December 31, 2009.

Outlook – Liberty Water

Notwithstanding the slowdown in the U.S. economy, Liberty Water is not expecting any material reduction in customers in fiscal 2010. Liberty Water continues to provide water distribution and wastewater collection and treatment services, primarily in the southern and southwestern U.S., in communities that have traditionally experienced long term growth and that provide continuing future opportunities for organic growth.

Liberty Water is proceeding through the regulatory process with rate cases relating to a number of its facilities. The Black Mountain facility filed a rate case in December 2008 using a June 30, 2008 test year. The LPSCo facility filed a rate case in March 2009 using a September 2008 test year. The Rio Rico facility filed a rate case in May 2009, using a test year ended December 31, 2008. The Bella Vista, Northern Sunrise and Southern Sunrise facilities filed rate cases in August 2009 using a March 31, 2009 test year. All of these facilities are located in Arizona. Five Texas facilities filed rate cases in April 2009, and Woodmark in Texas filed in July 2009, all with test years ended December 31, 2008.

The following table sets out some particulars with respect to the status of the rate cases as at February 15, 2010:

Facility	Test Year Ending	Status of Rate Case Application	Estimated Annual U.S. $ Revenue Increase as Filed	Estimated Timing of Rate Increase
Arizona				
Black Mountain	**Q2 2008**	Hearing has concluded. Awaiting Recommended Order & Opinion	$ 0.9 million	**Q2 2010**
LPSCo	**Q3 2008**	Hearing has concluded. Awaiting Recommended Order & Opinion	$ 12.5 million	**Q2/Q3 2010**
Rio Rico	**Q4 2008**	Direct Testimony filed on February 1, 2010 hearing scheduled for March 10-12, 2010	$ 2.0 million	**Q3 2010**
Bella Vista, Northern and Southern Sunrise	**Q1 2009**	Responding to interrogatories, hearing scheduled for June 28 – July 1, 2010	$ 1.5 million	**Q4 2010**
Texas				
Texas Utilities (Silverleaf – 4 utilities)	**Q4 2008**	Awaiting administrative hearing date	$ 1.2 million	**Interim rates implemented October 2009**
Tall Timbers	**Q4 2008**	Discovery period	$ 0.2 million	**Interim rates implemented July 2009**
Woodmark	**Q4 2008**	Public consultation period	$ 0.1 million	**Interim rates implemented January2010**

Rate cases ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Water monitors current and anticipated operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments.

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

In July 2009, Tall Timbers implemented interim rates to customers in a portion of its service area as applied for in its rate case application. The interim rates are being contested by various homeowner associations in Tall Timbers service area affected by the increase. These rates are expected to be finalized before the end of 2010 as part of the normal regulatory process administered by the TCEQ.

In October 2009, the Texas Silverleaf utility began charging interim rates based on its rate case applications. The interim rates are being contested by greater than 10% of the customers in the service area. These rates are expected to be finalized before the end of 2010 as part of the normal regulatory process administered by the TCEQ.

In Arizona, the Arizona Corporate Commission requires a full regulatory process for all rate cases using a historic test year. It is anticipated that the regulatory review of the proposed rates and tariffs for the Arizona facilities would be completed by mid-2010, with the new rates and tariffs in Arizona going into effect throughout 2010.

An exact determination of increased revenues from all rate case applications is not possible at this time as the timing of conclusion to the rate cases and the final decision on rate increases are determined by the regulator. As a result of delays in the progress of rate cases through the regulatory processes, Liberty Water now anticipates that approximately $7 million of additional revenue from rate cases will be achieved in 2010 but the full annualized increase in revenues determined through the rate case processes is expected to be achieved in 2011.

APUC: Corporate

	Three months ended December 31		Twelve months ended December 31	
	2009	2008	2009	2008
Corporate and other expenses:				
Administrative expenses	**2,531**	2,812	**10,712**	9,419
Management costs	**211**	224	**850**	893
Write down of property and notes	**6,457**	—	**6,457**	—
Management internalization expense	**4,693**	—	**4,693**	—
Other corporatization expenses	**3,460**	—	**3,460**	—
Loss / (Gain) on foreign exchange	**(258)**	2,339	**(1,261)**	4,018
Interest expense	**5,645**	5,711	**21,387**	26,288
Interest, dividend and other Income	**(6)**	(962)	**(58)**	(1,779)
Loss (gain) on derivative financial instruments	**(1,515)**	31,126	**(17,318)**	37,748
Income tax expense (recovery)	**(10,662)**	(4,438)	**(17,927)**	308

OVERVIEW

2009 Annual Corporate and Other Expenses

During the year ended December 31, 2009, administrative expenses totalled $10.7 million as compared to $9.4 million in the same period in 2008. The expense increase in the twelve months ended December 31, 2009 was primarily due to increased costs associated with additional staff added requirements to administer APUC's operations as compared to the same period in 2008.

In December 2009, APCo decided to dispose of its investments in its remaining LFG facilities and its 50% ownership in the Drayton Valley facility. APCo tested its investments for recoverability using a net realizable value valuation technique. As a result, Algonquin determined that these assets were impaired as at December 31, 2009. Accordingly, for the year ended December 31, 2009, APCo recognized an impairment charge of $1.1 million against the outstanding principal balance of a note receivable related to its LFG operations. APUC also wrote down the carrying value of its remaining LFG facilities and its 50% investment in the Valley Power facility to their estimated current fair value. This resulted in a write down of property and equipment of $4,854 in the period representing the difference between the carrying value of the assets and their net realizable values. Both of these assets are currently reported under the Algonquin Power – Thermal Division reporting segment. These assets generated gross revenues of $4.3 million in 2009.

For the year ended December 31, 2009, APUC recorded an expense of $4.7 million with regards to an agreement to acquire the Manager's interest in the management services agreement and internalize management as compared to nil in the same period in 2008. On December 21, 2009, APUC's Board ratified an agreement in principal with the shareholders of APMI to acquire the management contract and internalize management. Senior management expenses will be recorded within the Administrative Expense category on a go forward basis (See – Major highlights in 2009 – Management Internalization).

During the year ended December 31, 2009, APUC recorded an expense of $3.5 million associated with costs of converting the Fund to a corporation as compared to nil in the same period in 2008. The expense in the twelve months ended December 31, 2009 primarily consists of $1.5 million related to professional fees associated with the unit exchange transaction completed on October 27, 2009, increased capital taxes of $0.8 million as a result of the conversion to a corporation and an expense of $1.3 million associated with the exchange of the Series 1 Debentures for Series 1A Debentures (See – Shareholders Equity and Convertible Debentures).

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and do not impact APUC's current cash position. For purposes of evaluating divisional performance, APUC does not allocate the foreign exchange gains or losses to specific divisions as the change does not impact APUC's current cash position or cash generated from operations. For the year ended December 31, 2009, APUC reported a foreign exchange gain of $1.3 million as compared to a loss of $4.0 million during the same period in 2008. The twelve months ended December 31, 2009 experienced a decrease in value of the U.S. dollar of 15% which resulted in unrealized gains on APUC's U.S. denominated debt and working capital balances from its integrated U.S. operating facilities. The comparable period in 2008 experienced an increase in the value of the U.S. dollar of 22%, which resulted in unrealized losses on APUC's U.S. denominated debt. As at December 31, 2009, APUC had approximately $32.5 million in U.S. dollar denominated debt.

For the year ended December 31, 2009, interest expense totalled $21.4 million as compared to $26.3 million in the same period in 2008. Decreased interest expense was primarily related to lower interest rates charged on APUC's variable interest rate credit facilities and lower average borrowings, as compared to the prior year.

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

On October 27, 2009, as a result of the Unit Exchange Offer, the Fund converted from a publicly traded income trust to a publicly traded corporation (see "Major Highlights in 2009 - Conversion to a Corporation"). APUC's calculation of current and future income taxes for the year ended December 31, 2009 is based on the conversion to a corporate structure effective October 27, 2009, whereas APUC's calculation of current and future income taxes for the year ended December 31, 2008 is based on APUC being a publicly traded income trust. An income tax recovery of $17.9 million was recorded in 2009, as compared to an expense of $0.3 million during the same period in 2008. The primary reasons for this recovery relates to the conversion to a corporation from an income trust, decreases in expected future income tax rates, tax losses on U.S. operations resulting from bonus depreciation and lower energy and natural gas prices as compared to the same period in 2008 and the recovery of non-deductible interest expense related to U.S. operations, partially offset by additional future income tax liabilities resulting from the temporary differences in tax expenses related to CD and unit exchange issue costs and the reversal in the current year of unrealized losses on derivative financial instruments booked in the prior fiscal year. This resulted in an increased future tax recovery recorded in the twelve months ended December 31, 2009. (see Risk Management – Changes to income tax laws).

2009 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2009, administrative expenses totalled $2.5 million, as compared to $2.8 million in the same period in 2008. The expense increase in the three months ended December 31, 2009 primarily relates to added requirements to administer APUC's operations as compared to the same period in 2008.

In December 2009, APCo decided to exit its underperforming investments LFG facilities and Valley Power. See the discussion in the annual corporate results section, above, for details related to this expense.

For the quarter ended December 31, 2009, APUC recorded an expense of $4.7 million with regards to an agreement to acquire the Manager's interest in the management contract and internalize management as compared to nil in the same period in 2008. See the discussion in the annual corporate results section and 'Major highlights in 2009 – Management Internalization', above, for details related to this expense.

During the quarter ended December 31, 2009, APUC recorded an expense of $3.5 million associated with costs of converting the Fund to a corporation as compared to nil in the same period in 2008. The expense is discussed in more detail in the annual corporate results section, above.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and do not impact current cash position. For purposes of evaluating divisional performance, APUC does not allocate the foreign exchange gains or losses to specific divisions as the change does not impact APUC's current cash position or cash generated from operations. For the three months ended December 31, 2009, APUC reported a foreign exchange gain of $0.3 million as compared to a loss of $2.3 during the same period in 2008. The three months ended December 31, 2009 experienced a decrease in value of the U.S. dollar of 2% which resulted in unrealized losses on APUC's U.S. denominated debt and working capital balances from its integrated U.S. operating facilities. The comparable period in 2008 experienced an increase in the value of the U.S. dollar of 16%, which resulted in unrealized losses on APUC's U.S. denominated debt.

For the quarter ended December 31, 2009, interest expense totalled $5.6 million as compared to $5.7 million in the same period in 2008. Decreased interest expense was related to lower interest rates charged on APUC's variable interest rate credit facilities and lower average borrowings, as compared to the prior year.

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

An income tax recovery of $10.7 million was recorded in the three months ended December 31, 2009, as compared to a recovery of $4.4 million during the same period in 2008. The primary reasons for this recovery are discussed in the annual income tax expense section above (see Risk Management – Changes to income tax laws).

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

EBITDA is a non-GAAP metric used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of depreciation and amortization expense which are derived from a number of non-operating factors, accounting methods and assumptions. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the 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		Twelve months ended December 31	
	2009	2008	2009	2008
Net earnings (loss)	**$ (1,366)**	(21,095)	**$ 31,257**	$(19,038)
Add:				
Income tax provision (recovery)	**(10,662)**	(4,438)	**(17,927)**	308
Write down of property and notes	**6,457**	—	**6,457**	—
Management internalization expense	**4,693**	—	**4,693**	—
Other corporatization expenses	**3,460**	—	**3,460**	—
Interest expense	**5,645**	5,712	**21,387**	26,288
(Gain) / loss on derivative financial instruments	**(1,515)**	31,126	**(17,318)**	37,748
(Gain) / loss on foreign exchange	**(258)**	2,339	**(1,261)**	4,018
Amortization	**11,350**	11,536	**45,883**	43,846
Other	**223**	(1,924)	**2,737**	(3,142)
Adjusted EBITDA	**$ 18,027**	$ 23,256	**$ 79,368**	$ 90,028

For the quarter ended December 31, 2009, Adjusted EBITDA decreased by $5.2 million compared to the same period in 2008. The decrease in Adjusted EBITDA in the quarter ended December 31, 2009 is primarily due to $4.4 million in lower earnings from operations and $1.1 million in decreased interest, dividend and other income earned in the year as compared to the previous quarter.

For the year ended December 31, 2009, Adjusted EBITDA decreased by $10.7 million compared to the same period in 2008. The decrease in Adjusted EBITDA in the twelve months ended December 31, 2009 is due to $8.8 million in lower earnings from operations, $1.3 million in increased administration expenses and $0.6 million in decreased interest, dividend and other income earned in the year.

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

Adjusted net earnings is a non-GAAP metric used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact and are viewed as not directly related to a company's operating performance. Net earnings/(loss) of APUC can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. APUC uses adjusted net earnings to assess the performance of APUC without the effects of gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of APUC's businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the 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/(loss) to adjusted net earnings exclusive of these items:

	Three months ended December 31		Twelve months ended December 31	
	2009	2008	2009	2008
Net earnings	**$ (1,366)**	$(21,095)	**$ 31,257**	$(19,038)
Add:				
Loss (gain) on derivative financial instruments, net of tax	**(757)**	27,595	**(13,378)**	33,808
Write down of property and notes, net of tax	**6,379**	—	**6,379**	—
Management internalization expense, net of tax	**4,693**	—	**4,693**	—
Other corporatization expenses, net of tax	**2,813**	—	**2,813**	—
Loss (gain) on foreign exchange, net of tax	**(258)**	2,339	**(1,261)**	4,018
Adjusted net earnings	**$11,504**	$ 8,839	**$ 30,503**	$ 18,788
Adjusted net earnings per share/unit *	**$ 0.14**	$ 0.12	**$ 0.38**	$ 0.25

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

The increase in adjusted net earnings in the three months ended December 31, 2009 is primarily due to future income tax recoveries in the current year compared to future income tax expenses in the previous year, partially offset by lower earnings from operations. The reasons for future income tax recoveries are discussed in the APUC – Corporate section above.

The increase in adjusted net earnings in the twelve months ended December 31, 2009 is due primarily to by future income tax recoveries in the current year compared to future income tax expenses in the previous year partially offset by lower earnings from operations. The reasons for future income tax recoveries are discussed in the APUC – Corporate section above.

SUMMARY OF PROPERTY, PLANT AND EQUIPMENT EXPENDITURES BY BUSINESS SUBSIDIARY

	Three months ended December 31		Twelve months ended December 31	
	2009	2008	2009	2008
ALGONQUIN POWER CO.				
Renewable Energy Division				
Maintenance expenditures	**$ 472**	$ 353	**$ 902**	$ 1,280
Growth and other expenditures	**8**	439	**212**	8,144
Total	**$ 480**	$ 792	**$ 1,114**	$ 9,424
Thermal Energy Division				
Maintenance expenditures	**$ 664**	$ 1,212	**$ 2,398**	$ 3,457
Growth and other expenditures	**—**	1,853	**1,123**	4,985
Total	**$ 664**	$ 3,065	**$ 3,521**	$ 8,442
LIBERTY WATER CO.				
Capital Investment in regulatory assets	**$ (477)**	$ 4,785	**$ 6,174**	$35,712
Consolidated (includes Corporate)				
Maintenance expenditures	**$ 1,136**	$ 1,713	**$ 3,407**	$ 4,995
Capital investment in regulatory assets	**(477)**	4,785	**6,174**	35,712
Growth and other expenditures	**8**	2,291	**1,335**	13,128
Total	**$ 667**	$ 8,789	**$10,916**	$53,835

APUC's consolidated capital expenditures in 2009 remained lower than in 2008 due to a number of large capital projects that were completed in 2008. The larger capital projects completed in 2008 were APCo's BCI project, the Sanger re-powering project, and the acquisition of the Campbellford hydroelectric facility. Liberty Water in 2008 incurred larger growth related capital projects particularly at the LPSCo facility.

Property, plant and equipment expenditures for the 2010 fiscal year are anticipated to be between $14.0 million and $20.0 million, including approximately $2.0 million related to ongoing requirements in Liberty Water, $6.7 million related to the APCo Thermal division, and $4.0 million related to the APCo Renewable Energy division.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, working capital and bank credit facilities to finance its property, plant and equipment expenditures and other commitments.

2009 Annual Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2009, APUC incurred growth and other property, plant and equipment expenditures of $1.3 million, as compared to $13.1 million during the comparable period in 2008. APCo invested $3.4 million in property, plant and equipment during the twelve months ended December 31, 2009, as compared to $5.0 million during the comparable period in 2008. In addition, Liberty Water invested $6.2 million in property, plant and equipment during the twelve months ended December 31, 2009, as compared to $35.7 million during the comparable period in 2008.

During the twelve months ended December 31, 2009, APCo Renewable Energy division's expenditures primarily relate to investments in the Great Falls and Franklin hydroelectric facilities. During the comparable period in 2008, the APCo Renewable Energy division's expenditures primarily relate to the Campbellford acquisition, a 4MW hydroelectric generating facility located on the Trent-Severn Waterway approximately four kilometres north of Campbellford, Ontario, and projects at Great Falls and Dickson Dam.

During the twelve months ended December 31, 2009, APCo Thermal Energy division's expenditures primarily related to investments at the Dynafibres, EFW and BCI facility. In the comparable period, the expenditures primarily related to the completion of the Sanger re-powering project, investment in the Windsor Locks facility, the BCI steam sales facility and the EFW facility.

During the twelve months ended December 31, 2009, Liberty Water's investment in property, plant and equipment primarily relate to completion and commissioning of projects initiated in 2008, additional well capacity and engineering work, including approximately $4.1 million of advances from developers and an investment in certain non-utility assets, a portion of which was sold during the year. During December 2009, Liberty Water refunded an advance from a developer which resulted in a $3.4 million reduction of in the book value of property plant and equipment and a corresponding reduction in net property plant and equipment expenditures recorded in the period.

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

2009 Fourth Quarter Property Plant and Equipment Expenditures

During the quarter ended December 31, 2009, APUC incurred growth and other property, plant and equipment expenditures of nil, as compared to $2.3 million during the comparable period in 2008. APCo incurred net investment in property, plant and equipment $1.1 million during the quarter ended December 31, 2009, as compared to $1.7 million during the comparable period in 2008. In addition, Liberty Water incurred negative net investment in property, plant and equipment of $0.5 million during the quarter ended December 31, 2009, as compared to net investment of $4.8 million during the comparable period in 2008.

During the three months ended December 31, 2009, the Renewable Energy division's expenditures were not significant. During the comparable period in 2008, the Renewable Energy division's expenditures primarily related to various projects at Great Falls and Dickson Dam.

During the three months ended December 31, 2009, the Thermal Energy division's expenditures were not significant. During the comparable period in 2008, the Thermal Energy division's expenditures primarily related to investments in the Sanger, BCI and Windsor Locks facilities.

During the three months ended December 31, 2009, Liberty Water investment in property, plant and equipment primarily related to a number of general projects including approximately $2.5 million of advances from developers, less the refund of an advance from a developer noted in the discussion of annual expenditures above. In the comparable period, the expenditures primarily related to investment in additional wells, engineering work regarding wastewater treatment operations and arsenic treatment at the LPSCo facility. As previously noted, these investments have been included in the rate case applications which are currently in process.

LIQUIDITY AND CAPITAL RESERVES

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

	2009 Q4	2009 Q3	2009 Q2	2009 Q1	2008 Q4
Committed and available bank credit facilities	$179,500	$ 176,700	$ 189,050	$ 192,750	$ 192,750
Funds Drawn on credit facilities	(94,000)	(129,000)	(134,000)	(129,500)	(137,000)
Letters of Credit issued	(33,100)	(33,400)	(35,250)	(37,600)	(37,500)
Remaining available bank facilities	**$ 52,400**	**$ 14,300**	**$ 19,800**	**$ 25,650**	**$ 18,250**
Cash on Hand	2,800	7,700	6,900	900	5,900
Total liquidity and capital reserves	**$ 55,200**	**$ 22,000**	**$ 26,700**	**$ 26,550**	**$ 24,150**

As at and for the period ended December 31, 2009, APUC and the Fund are in compliance with the covenants under its Facilities.

As at December 31, 2009, $94.0 million had been drawn on the Facilities as compared to $137.0 million as at December 31, 2008. In addition to amounts actually drawn, there was $33.1 million in letters of credit currently outstanding as at December 31, 2009. As at December 31, 2009, APUC and its subsidiaries had $52.4 million of committed and available bank facilities remaining and $2.8 million of cash resulting in $55.2 million of total liquidity and capital reserves.

The term of the Facilities matures on January 14, 2011. Subsequent to December 31, 2009, APUC initiated discussions with its senior lenders with regards to entering into a new multi-year term senior debt facility.

As at December 31, 2009, in addition to the liquidity and capital reserves noted above, APUC also had $40.0 million in short term investments available to complete the acquisition of three hydroelectric generating assets located in New Brunswick and Maine having a capacity of 36.8 MW, most notably the 34.5MW Tinker Hydroelectric station located on the Aroostook River near the Town of Perth-Andover, New Brunswick.

CONTRACTUAL OBLIGATIONS

Information concerning contractual obligations as of December 31, 2009 is shown below:

	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Long term debt obligations	$244,772	$ 3,360	$166,051	$ 3,594	$ 71,767
Convertible Debentures	$190,160	—	—	66,943	123,217
Interest on long term debt obligations	$157,705	21,685	38,555	39,723	57,742
Purchase obligations	$ 33,219	33,219	—	—	—
Derivative financial instruments:					
Currency forward	$ 1,469	—	1,475	(6)	—
Interest rate swap	$ 8,226	5,775	2,025	417	9
Capital lease obligations	$ 456	145	302	5	4
Other obligations	$ 10,143	515	1,025	1,025	7,578
Total obligations	$646,150	$ 64,699	$209,433	$111,701	$260,317

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

SHAREHOLDER'S EQUITY AND CONVERTIBLE DEBENTURES

On October 27, 2009, pursuant to the Unit Exchange Offer, all the Fund's trust units were exchanged for shares of APUC that began to be publicly traded on the Toronto Stock Exchange while the Fund's trust units concurrently ceased trading on the Toronto Stock Exchange.

As at December 31, 2009, APUC had 93,064,120 issued and outstanding shares on a fully diluted basis.

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

On December 2, 2009, APUC issued 6,877,000 common shares at $3.35 each for net proceeds of $21.9 million after underwriting expenses and before additional issuance costs (gross proceeds of $23.0 million).

Pursuant to the takeover bid of AirSource Power Fund I LP ("Airsource"), on September 29, 2006 the Fund issued trust units and a subsidiary issued limited partnership units which were exchangeable into trust units of the Fund at the holder's option (the "Exchangeable Units"). The Fund issued 1,021,449 trust units during the fourth quarter on and prior to October 27, 2009, and 1,473,647 trust units during the period ended October 27, 2009 pursuant to the conversion of Exchangeable Units. These trust units were converted to shares of APUC as a result of the Unit Exchange Offer.

At a special meeting of Exchangeable Unitholders of Airsource in December 2009, amendments were approved to amend the agreements related to the Exchangeable Units to allow the exchange of Exchangeable Units for common shares of APUC, as opposed to units of the Fund, and to change the definition of "Redemption Date" as set out in the Airsource partnership agreement. As a result of these changes, APUC exercised the compulsory acquisition provisions contained in the documentation relating to the Exchangeable Units on December 31, 2009 and all of the remaining outstanding Exchangeable Units were exchanged for 532,074 common shares of APUC, as per the formula set out in the original agreements. As a result, there are no outstanding Exchangeable Units as of December 31, 2009.

On August 1, 2008, the Fund issued 3,507,143 trust units in exchange for cash and securities of approximately $27.0 million or $7.69 per unit. The unit issue was pursuant to an agreement entered into on September 27, 2008 between the Fund, Highground Capital Corporation ("Highground") (previously Algonquin Power Venture Fund) and CJIG Management Inc. ("CJIG"). Under the agreement CJIG acquired all of the issued and outstanding common shares of Highground, and the Fund issued 3,507,143 trust units, of which 3,065,183 trust units were received by Highground shareholders as part of the agreement with the remaining trust units being retained by CJIG.

During 2009, the Fund received $983 from CJIG as additional proceeds of the share issuance from assets obtained in the transaction and from the Fund's share of the additional proceeds from the further liquidation of the assets held by Highground in excess of $26,970. This has been recorded as an increased amount assigned to the trust units originally issued. The remaining investments, formerly held by Highground, currently consist of two non-liquid debt assets having a book value of $2.4 million. The payments on these assets are current and the debt matures in 2010 and in 2012. The Fund's 50% share of any additional proceeds from liquidation of the remaining Highground assets will be recorded when received as additional proceeds from the issuance of units in future periods.

In July 2004, the Fund issued 85,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on July 31, 2011 ("Series 1 Debentures"). The Series 1 Debentures bore interest at 6.65% per annum and were convertible into trust units of the Fund at the option of the holder at a conversion price of $10.65 per trust unit, being a ratio of approximately 93.9 trust units for each $1,000 principal. On October 27, 2009, there were 84,964 convertible debentures outstanding with a face value of $84,964.

Pursuant to the CD Exchange Offer, on October 27, 2009, $63,755 of the outstanding Series 1 Debentures were exchanged for convertible debentures bearing interest at 7.5%, maturing on November 30, 2014 (“Series 1A Debentures”) convertible unsecured subordinated debentures in a principal amount of $66,943. The Series 1A Debentures pay interest semi-annually in arrears on January 1 and July 1 each year and are convertible into shares of APUC at the option of the holder at a conversion price of $4.08 per share, being a ratio of approximately 245.1 shares for each $1,000 principal. The Series 1A Debentures may not be redeemed by APUC prior to January 1, 2011. During the period of January 2, 2011 until January 1, 2012, the debentures may be redeemed by APUC if the underlying share price is equal to or exceeds a price of $5.10 (125% of the conversion price of $4.08). During the period of January 2, 2012 until the debenture’s maturity, APUC can redeem the debentures for 100% of the face value of debenture with cash, or for 105% of the face value of debenture with additional shares. On December 31, 2009, there were 66,943 Series 1A Debentures outstanding with a face value of $66,943.

The remaining Series 1 Debentures having a face value of $21,209, not converted to Series 1A Debentures pursuant to the CD Exchange Offer, were exchanged for 6,607,027 shares of APUC.

In November 2006, the Fund issued 60,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on November 30, 2016 (“Series 2 Debentures”). The Series 2 Debentures bore interest at 6.2% per annum and were convertible into trust units of the Fund at the option of the holder at a conversion price of $11.00 per trust unit, being a ratio of approximately 90.9 trust units for each $1,000 principal. During the three months ended December 31, 2009 and prior to October 27, 2009, Series 2 Debentures valued at $33,000 were exchanged into 3,000 trust units. These trust units were converted to shares of APUC as a result of the Unit Exchange. On October 27, 2009, there were 59,967 Series 2 Debentures outstanding with a face value of $59,967.

Pursuant to the CD Exchange Offer, on October 27, 2009, all of the outstanding Series 2 Debentures were exchanged for convertible unsecured subordinated debentures bearing interest at 6.35%, maturing on November 30, 2016 (“Series 2A Debentures”) in a principal amount of $59,967. The Series 2A Debentures pay interest semi-annually in arrears on April 1 and October 1 each year and are convertible into shares of APUC at the option of the holder at a conversion price of $6.00 per share, being a ratio of approximately 166.7 shares for each $1,000 principal. The Series 2A Debentures may not be redeemed by APUC prior to January 1, 2011. During the period of January 2, 2011 until January 1, 2012, the debentures may be redeemed by APUC if the underlying share price is equal to or exceeds a price of $7.50 (125% of the conversion price of $6.00). During the period of January 2, 2012 until the debenture’s maturity, APUC can redeem the debentures for 100% of the face value of debenture with cash, or for 105% of the face value of debenture with additional shares. On December 31, 2009, there were 59,967 Series 2A Debentures outstanding with a face value of $59,967.

On December 2, 2009, APUC issued 63,250 convertible unsecured debentures at a price of $1,000 for each debenture maturing on June 30, 2017 (“Series 3 Debentures”). APUC received net proceeds of $60.7 million after underwriting expenses and before additional issuance costs (gross proceeds of $63.3 million). The Series 3 Debentures bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year, and are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares for each $1,000 principal. The Series 3 Debentures may not be redeemed by APUC prior to December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 Debentures may be redeemed by APUC only if the underlying share price is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 Debentures’ maturity, APUC can redeem the Series 3 Debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 Debentures with additional shares. On December 31, 2009, there were 63,250 Series 3 Debentures outstanding with a face value of $63,250.

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 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

The following related party transactions occurred during the year ended December 31, 2009:

- APMI provided management services including advice and consultation concerning business planning, support, guidance and policy making and general management services to APUC. In 2009 and 2008, APMI was paid on a cost recovery basis for all costs incurred and charged $850 (2008 - $893). As discussed above (see – Management Internalization), on December 21, 2009, subject to regulatory and shareholder approval, APUC ratified the agreement to acquire this management contract from the shareholders of APMI. During 2009 $nil (2008 - $nil) was earned by APMI as an incentive fee.
- APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a net basis. Base lease costs for 2009 were $331 (2008 - $296). APUC believes the lease is on terms equivalent to fair market value for prime office space of similar size and quality at the time the lease was executed.
- APUC and its subsidiaries utilize chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Airlink. In 2004, the Fund entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC and its subsidiaries’ business use of the aircraft. Under the terms of this arrangement, APUC and its subsidiaries will have priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the year,

APUC incurred costs in connection with the use of the aircraft of $367 (2008 - $332) and amortization expense related to the advance against expense reimbursements of $153 (2008 - $90). At December 31, 2009, the remaining amount of the advance was $666 (2008 - $818). APUC believes the amounts paid for chartering the aircraft are equivalent to or better than fair market value terms otherwise available for chartering a similar aircraft.

- As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI, whereby APMI undertook certain construction management services on the project. The project was substantially completed in the fourth quarter of 2007 and APMI was entitled to a development supervision fee plus a performance based contingency fee for its construction management role on the project. During 2009, APMI was paid $nil (2008 - $23) for development supervision. During 2008, the Fund accrued $674 as the final fee owed to APMI with respect to this project. This fee has been accrued and is included in accounts payable on the consolidated balance sheet.
- In accordance with the construction services agreement related to the St. Leon facility a company controlled by APMI, was paid a final payment of $134 in 2008 for construction services.
- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), an indirect subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing June 17, 2008 growing to a maximum of 10% by year 15. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units are entitled to cash distributions of $292 for the year ended December 31, 2009 (2008 - $173).
- APMI is entitled to 50% of the cash flow above 15% return on investment for the BCI project pursuant to its project management contract. During 2009 and 2008, no amounts were paid under this agreement. However, APMI earned a construction supervision fee in 2008 of $100 in relation to the development of this project.
- On March 10, 2008, the Fund advanced $225 to the Trustees for purposes of enabling the Trustees to purchase additional trust units of the Fund. The loans were subject to promissory notes issued in favour of the Fund which were repayable upon demand and were recorded as a reduction in trust units on the consolidated balance sheet. On October 22, 2009 the loans were fully repaid. During 2008 a principal repayment of $8 was made.
- On June 27, 2008, the Fund entered into an agreement with Highground and CJIG to issue trust units in exchange for cash and securities held by Highground (see – Shareholder's Equity and Convertible Debentures). Pursuant to the agreement APMI was entitled to a fee of approximately $240 from the Fund. This fee was paid in 2009.
- Up to August 1, 2008, APUC had project debt from Highground in the amount of $3,000 related to the St. Leon facility. Highground advanced $1,600 at a rate of 11.25% as part of the initial financing of the St. Leon facility and advanced $1,400 at a rate of 9.25% during the first quarter of 2007. These amounts have now been eliminated on the consolidated balance sheet due to the acquisition of securities held by Highground.
- Up to July 31, 2008, Highground was paid $150 (2007 - $150) in interest related to debt associated with the St. Leon facility. Some of the directors and shareholders of APMI were also directors, officers and shareholders of the manager of Highground.

TREASURY RISK MANAGEMENT

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

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, any credit risk associated with a reliance on key customers, interest rate, liquidity and commodity price risk considerations. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the 2009 Annual Information Form.

Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 45% of EBITDA and 60% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in increased reported revenue from U.S. operations of approximately $9.6 million and increased reported expenses from U.S. operations of approximately $6.4 million or a net impact of $3.2 million ($0.035 per share) on an annual basis.

The Fund previously managed this risk primarily through the use of forward contracts as it required U.S. dollar cash inflows to meet Canadian dollar cash outflows. As a result of the current business strategy and lower payout ratio, APUC has determined that the prior practice of hedging 100% of its U.S. currency exposure is no longer appropriate and is taking steps to eliminate its existing forward currency contract program and during the quarter ended December 31, 2009, APUC terminated forward contracts of $37.2 million for net proceeds of $0.1 million. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes. For the year ended December 31, 2009 APUC realized a $0.3 million loss on forward contracts settled during the period.

The following chart sets out the amount of foreign exchange forward contracts outstanding as at December 31, 2009, hedge proceeds and average hedged rates over the term of the contracts:

	Total	2010	2011	2012	2013
Total U.S. $ Hedged	$39,760	$—	$26,450	$12,560	$ 750
Total Can. $ Proceeds	$40,460	—	26,793	12,864	803
Average Hedged Rate	$ 1.018	n/a	$ 1.013	$ 1.024	$1.070
Unrealized Gain (loss)	**$ (1,469)**	n/a	**(1,084)**	**(391)**	**6**
Impact of a $0.10 move in exchange rates	**$ 3,976**	n/a	**$ 2,645**	**$ 1,256**	**$ 75**

Based on the fair value of the forward contract using the exchange rates as at December 31, 2009, the exercise of these forward contracts will result in the use of cash of $1.1 million in fiscal 2011 and result in the use of cash of $0.4 million for the remainder of the hedged period beyond 2011. Assuming a decrease in the strength of the US dollar relative to the Canadian dollar of $0.10 at December 31, 2009, with a corresponding increase in the forward yield curve, the fair value of the outstanding forward exchange contracts would increase by $4.0 million, resulting in the generation of additional cash of $1.6 million in fiscal 2011, and the generation of $0.9 million in cash for the remainder of the hedged period beyond 2011.

Market price risk

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

Subsequent to December 31, 2009, as a result of the acquisition of the Energy Services Business on February 4, 2010, APCo provides the short-term energy requirements to various customers at fixed rates. These customers include energy sales to a town in New Brunswick, Standard Offer Service contract with three local municipal electric utilities in northern Maine, and a series of direct energy contracts with commercial buyers also in northern Maine. The energy requirements of these customers are estimated at approximately 150,000 MW-hrs on an annualized basis. While the Tinker Assets are expected to provide the majority of the energy required to service these customers, the Energy Services Business anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy. In the event that the Energy Services Business was required to purchase all of its energy requirements at ISO NE spot rates, each $10.00 change per MW-hr in the market prices in ISO NE would result in a change in expense of $1.5 million on an annualized basis.

This risk is mitigated though the use of short term energy hedges contracts. APCo has committed to acquire 12,500 MW-hrs of energy over the next 13 months at an average rate of approximately $75 per MW-hr.

Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its trade receivables. APUC does not believe this risk to be significant as approximately 90% of APCo Renewable Energy division's revenue, approximately 80% of APCo Thermal Energy division's revenue, and over 65% of total revenue 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 following chart sets out APCo's significant counterparties, their credit ratings and percentage of total revenue associated with the counterparty:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Manitoba Hydro	AA	19,800	29%
Hydro – Quebec	A+	21,700	32%
Ontario Electricity Financial Corporation	A+	10,800	16%
Public Service Company of New Hampshire	BBB	4,400	7%
National Grid	A-	3,500	5%
Total		**$ 60,200**	**88%**
Thermal Energy Division			
Connecticut Light and Power Company	BBB	23,200	29%
Pacific Gas and Electric Company	BBB+	16,300	20%
Ahlstrom	1R3**	11,700	15%
Regional Municipality of Peel	AAA	14,500	18%
Total		**$ 65,700**	**82%**

* Ratings by Standard & Poor's as of January 2010

** Ratings by Dunn & Bradstreet as of February 2010

The remaining revenue is primarily earned by Liberty Water. In this regard, the credit risk related to Liberty Water accounts receivable balances of US $2.9 million is spread over approximately 68,000 customers, resulting in an average outstanding balance of less than $50.00 per customer. Liberty Water has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

Interest rate risk

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

- The Fund's senior debt facility had a balance of $94.0 million as at December 31, 2009. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.9 million annually. The Fund has fixed for floating interest rate swaps in an amount of $100.0 million which fix the interest expense on $100.0 million of borrowings at approximately 4.125% for 2010. This reduces volatility in the interest expense on this debt. The financial impact of any changes in interest rates are partially offset between the change in interest expense and the change in the underlying value of the interest rate swap. At December 31, 2009, the mark to market value of the interest rate swap was a net $3.3 million liability (December 31, 2008 – net $5.5 million liability).
- APCo's project debt at the St. Leon facility had a balance of $70.5 million as at December 31, 2009. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.7 million annually. Although the underlying debt with the project lenders carries variable rate of interest tied to the Canadian bank's prime rate, APCo has entered into a fixed for floating interest rate swap on this project specific debt until September 2015 which mirrors the underlying debt's interest and principal repayment schedule. This minimizes volatility in the interest expense on this debt. The financial impact of interest rate changes are effectively offset between the change in interest expense and the change in value of the interest rate swap. APCo has effectively fixed its interest expense on its senior debt facility at 5.47%. At December 31, 2009, the mark to market value of the interest rate swap was a net liability of $5.0 million (December 31, 2008 – liability of $11.3 million).

- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2009. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.2 million annually.

Liquidity risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due. APUC's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

APUC currently pays a dividend of $0.24 per share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements and to fund working capital that, in their judgment, ensure APUC's long-term success. Based on the current level dividends paid during the year ended December 31, 2009, cash provided by operating activities exceeded dividends declared by 2.6 times.

As at December 31, 2009, APUC had cash on hand of $2.8 million and $52.4 million available to be drawn on committed credit facilities from its bank syndicate. The term of the Facilities matures on January 14, 2011. Subsequent to December 31, 2009, APUC initiated discussions with its senior lenders with regards to entering into a new multi-year term senior debt facility. See the Liquidity and Capital Reserves section for a more detailed discussion and chart of the funds available to APUC and its subsidiaries under its credit facilities.

The Facilities and project specific debt total approximately $244.8 million with maturities set out in the Contractual Obligation table above. In the event that APUC was required to replace these Facilities with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment into the company may be negatively impacted. APUC attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

The cash flow generated from several of APUC's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regards 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. In this regard, a discussion of this risk is set out as follows:

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

- APCo's Windsor Locks facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $0.8 million on an annual basis.
- APCo's BCI facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $0.3 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of $0.4 million or a net increase in operating profits of approximately $0.1 million.

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. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter. A further assessment of APUC's business risks is also set out in the 2008 Annual Information Form.

Mechanical and Operational Risks

APUC is entirely dependant upon the operations and assets of APUC's businesses. Accordingly, dividends to shareholders are dependent upon the profitability of each 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 the Liberty Water 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.

These risks are mitigated through the diversification of APUC's operations, both operationally (APCo and Liberty Water) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. In addition, APCo's existing long term PPAs minimize the risk of reductions in average energy pricing.

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.

The utility facilities are highly regulated and are subject to rate settings by State regulators. The operating companies are regulated utilities subject to the full regulation of the public utility commissions for 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 operate under cost-of-service regulation as administered by these State

authorities. The utilities use a historic test year subject to certain adjustments for known and measureable changes 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 the reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. These regulatory bodies have the authority to establish the allowed rate of return on approved rate base and also determine which investments are approved for inclusion in the rate base which in both cases can affect the profitability of the division. If the utilities are unable to obtain government approval of requested rate increases, or if rate increases are untimely or inadequate to cover capital investments and to recover expenses, profitability could be affected.

Federal, State and local environmental laws and regulations impose substantial compliance requirements on water and wastewater utility operations. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Water and wastewater 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 Water, and while Liberty Water 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 Water regularly works with these 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. Based on its assessments, APUC's businesses do not have any significant retirement obligation liabilities and has not recorded any liability in its financial statements.

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 Renewable Energy division's 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 APCo Thermal Energy division's EFW facility owns the property on which its facility operates. EFW's current waste incineration agreement expires in 2012 with two five year options to extend. While APCo anticipates being in a position to renew or extend the existing contract in 2012, in the event that APCo is unable to renew or extend the agreement, APCo may choose to close the facility but has no legal obligation to remove the assets. Under the terms of the contract, the responsibility for removal of the bulk of any hazardous material generated in the operation of the facility remains with EFW's primary customer. As such, the potential expense to bring the facility in line with current environmental standards in the event it is eventually closed has been assessed as insignificant based on the quantification of costs to remediate the facility, expectation that the existing contract can be extended or renewed and that the potential timing of such an event, although unlikely, would be well in the future.

Liberty Water's facilities operate under agreements with a state or municipal regulator to provide the sole water distribution and/or wastewater treatment services in its area of operations, as set out in the agreements. In general, these 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 Water 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 Water is allowed to earn a return on its investment.

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. APCo has assessed the likelihood of these risks becoming a contingent environmental liability as remote; therefore APCo has not recorded any contingent liabilities on its financial statements.

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. In the aggregate, the departments comprise 7 full time equivalent positions based out of head office and have an annual budget of approximately $1.0 million, which includes wages, travel and other costs. Facility specific permitting and compliance expenses are direct operating expenses of each facility and are excluded from these expenses.

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. Each of APUC's businesses have 24 hour, 365 day emergency response and spill procedures in place in the event there is an oil or chemical spill.

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; 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, 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. 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 Water 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 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 Water 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 Water 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.

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.

Specific Environmental Risks

Greenhouse Gas Initiatives:

Several Northeastern US States have formed a coordination group to develop a multi state green house gas mitigation action plan. This group, the Regional Greenhouse Gas Initiative ("RGGI"), has received backing from several states where APCo operates facilities including Connecticut and New Jersey. 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 will be implemented to regulate CO2 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. As such APCo will be required to purchase approximately 250,000 tons of CO2 allowances per year, equivalent to the total annual CO2 emissions from the Windsor Locks facility for the 2009 to 2012 fiscal years. APCo is entitled to apply for allowances and/or purchase allowances at a base price of $2.00 per tonne from the state of Connecticut. APCo submitted an application on October 31, 2008 for allowances under the available programs. For 2010, APCo has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks facility to be between $0.2 and $0.4 million.

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"). This group recently released details of its Regional Cap-and-Trade Program, which is scheduled to start on January 1, 2012. 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 others in Ontario which could be impacted by this program. As this process has just begun, it is too early to determine the potential financial impact on APCo and means available to mitigate this financial impact, if any.

The Carbon Disclosure Project ("CDP") is an independent non-profit organization that represents institutional investors managing over $57.0 trillion of assets. The CDP is specifically working to encourage companies world wide to quantify and disclose their greenhouse gas emissions and to outline what actions the companies are taking to address climate change risk, both from potential physical impacts but also from regulatory changes that may result in an effort to address climate change.

APCo submitted a baseline greenhouse gas emissions inventory to the CDP at the end of June 2008. 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.

Renewable Energy Division:

As a result of certain legislation passed in Quebec (Bill C93), APCo is undertaking technical assessments of its hydroelectric facility dams owned or leased within the Province of Quebec. This is discussed in greater detail within the analysis of results in the Renewable Energy Division.

The province of Ontario is considering enacting new legislation similar to Bill C93. APCo operates four 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 expected capital costs related to the Quebec facilities, as there are fewer facilities in Ontario and they are of newer construction.

Liberty Water:

Liberty Water owns and operates the LPSCo facility, a water distribution and waste-water treatment utility servicing the City of Litchfield Park**,** and parts of the City of Goodyear, the City of Avondale and the County of Maricopa, Arizona, 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 LPSCo 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, LPSCo closely 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 LPSCo. EPA's monitoring and control efforts have not indicated that the concentrations are being reduced or fully captured. Additional remedial efforts by the EPA to stop advancement and reduce TCE concentrations are underway. In the event that any wells exceed EPA permitted TCE level, LPSCo 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 of removal of a well, there would remain sufficient production and reservoir capacity within the balance of the water distribution system to adequately service the needs of all of LPCSo's customers. In addition, LPSCo has identified alternate sites where replacement wells can be established to replace this lost capacity. The cost of establishing a new well is estimated to be between $2.0 million and $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, volume of water available at the new site, and acquisition of land and groundwater rights. Liberty Water does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.

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, 2009.

Seasonal fluctuations and hydrology

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the 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. For Liberty Water's water utilities, 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.

Wind resource

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.

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.

As reported in previous public filings of the Fund, Trafalgar Power, Inc. and Christine Falls Power Corporation (collectively, “Trafalgar”) commenced an action in 1999 in U.S. District Court against the Fund, APMI and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to the Fund and in connection with the foreclosure on the security for the Note which includes interests in Trafalgar entities that own hydroelectric generating facilities in New York. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the B Note, that the Fund was therefore the holder and owner of the B Note, and that all other claims by Trafalgar with respect to the transfer of the Note were without merit. In 2008 Algonquin filed for summary judgement seeking dismissal of Trafalgar’s remaining claims, and the District Court granted this motion on November 6, 2008. On October 22, 2009 Trafalgar filed an appeal from the November 6, 2008 summary judgement to the United States Court of Appeals for the Second Circuit. Financial loss to the Fund is not expected to result from the appeal.

Although APMI paid one half of the external legal fees incurred up to July 1, 2002 with respect to the Trafalgar dispute, APUC is funding the litigation. In the event of a recovery by APUC of all or part of the funds, APUC and APMI will divide such amounts in proportion to the amount of legal fees funded, after reimbursement of expenses.

On December 19, 1996, the Attorney General of Québec (“Québec AG”) filed suit in Québec Superior Court against Algonquin Développement Côte Ste-Catherine Inc. (Développement Hydromega), a predecessor company to an APUC subsidiary. The Québec AG at trial claimed $5.4 million for amounts that the APUC entities have been paying to the federal authority under its water lease with the authority. The APUC entities brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009. The Côte Ste-Catherine Facility currently pays water lease dues to the federal government, but if the Québec AG is successful in any appeal, an adjustment and/or increase of such amounts is possible.

Obligations to serve

Liberty Water’s utility facilities may be 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 Water may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

Tax risks associated with the Unit Exchange Offer

There is a possibility that the Canada Revenue Agency could successfully challenge the tax consequences of the Unit Exchange or prior transactions of Hydrogenics or that legislation could be enacted or amended resulting in different tax consequences from those contemplated in the Unit Exchange Offer 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.

Critical Accounting Estimates

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

Financial statements prepared in accordance with Canadian GAAP require management to make estimates and assumptions relating to reported amounts of revenue and expenses, reported amounts of assets and liabilities and disclosure of contingent assets and liabilities. APUC regularly evaluates the assumptions and estimates that are used in the preparation of APUC's Consolidated Financial Statements. Estimates and assumptions used by management are based on past experience and other factors deemed reasonable in the circumstances. Since these estimates and assumptions involve varying degrees of judgment and uncertainty, the amounts reported in the financial statements could in the future prove to be inaccurate.

APCo recognizes revenue derived from energy sales at the time energy is delivered. Revenue from waste disposal is recognized on an 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 are recognized based on actual tonnage at the expected price for the contract year and any amount billed in excess of the expected is deferred. Liberty Water revenue is recognized when processed and delivered to customers.

APUC records as other liabilities amounts received by Liberty Water which relate to advances from developers for water distribution and water reclamation main extensions received. These advances usually carry repayment terms based on the revenue generated by the development in question ranging over a specified period of time. At the end of the payment term, the unpaid portion of the advance converts to contribution in aid of construction and is not required to be repaid to the developer. The amount recorded as other liabilities is based on Liberty Water's expected repayments as determined by historical experience and industry practice.

Estimates are also made related to the useful life of long-lived assets. These estimates are used to determine amortization expense. Estimates of an asset's useful life are based on past experience with similar assets taking into account technological or other changes. If these estimates prove to be inaccurate, management may have to shorten the anticipated useful life of the assets recorded in the financial statements resulting in higher amortization expense in future periods or possibly an impairment charge to reflect the write-down in the value of the asset.

APUC and its subsidiaries also regularly assess whether there has been an impairment to long term investments, notes receivable, capital and intangible assets, and recoverability of future tax assets based on circumstances that may indicate APUC will not be able to recover the assets entire carrying value. Should impairment be deemed to have occurred, APUC would reduce the carrying value of that asset in the financial statements and deduct this amount from earnings. APUC cannot predict future events that could create impairment, or how future events might affect the carrying value of the assets' values reported in the financial statements.

Controls and Procedures

APUC's management is responsible for preparation and presentation of the Consolidated Financial Statements and MD&A. APUC's Consolidated Financial Statements have been prepared in accordance with GAAP. This MD&A has been prepared in accordance with the requirements of the Ontario Securities Commission including National Instrument 51-102 of the Canadian Securities Administrators.

Disclosure Control and Procedures

In accordance with the requirements of the *Securities Act (Ontario)* and other provincial securities legislation, the CEO and CFO of the Company certify interim quarterly and annual filings that they have designed APUC's disclosure controls and have evaluated their effectiveness for the applicable period. Disclosure controls are those controls and procedures which ensure that information that is required to be disclosed by Multilateral Instrument 52-109, the Ontario Securities Commission and other provincial regulators is recorded, processed and reported within the time frames specified by regulators. Disclosure controls and procedures are designed to ensure that information required to be disclosed by APUC is appropriately accumulated and communicated to management, including the CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosure.

An evaluation of the effectiveness of the design and operation of APUC's disclosure controls and procedures was carried out, under the supervision and with the participation of our management, including the CEO and the CFO, as appropriate, and was presented to the Disclosure Committee and to the Audit Committee. Based on that evaluation, the CEO and CFO concluded that disclosure controls and procedures were effective as of the end of such period.

Internal Control over Financial Reporting

The CEO and CFO of APUC are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian generally accepted accounting principles.

Under the supervision and with the participation of the CEO and the CFO, management conducted an evaluation of the effectiveness of our internal control over financial reporting, as of December 31, 2009, based on the framework set forth in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under this framework, management concluded that the internal control over financial reporting was effective as of that date.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by

collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Changes in Internal Control over Financial Reporting

There were no changes made in the year ended December 31, 2009 to the internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the internal control over financial reporting.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2009.

Millions of dollars (except per share amounts)	1st Quarter 2009	2nd Quarter 2009	3rd Quarter 2009	4th Quarter 2009
Revenue	$ 52.2	$ 46.5	$ 45.1	$ 43.4
Net earnings /(loss)	4.2	15.3	13.1	(1.4)
Net earnings / (loss) per share/trust unit	0.05	0.20	0.17	(0.03)
Total Assets	974.2	952.4	925.7	1,013.4
Long term debt*	457.6	456.2	445.4	439.9
Dividend/distribution per share/trust unit	0.06	0.06	0.06	0.06

	1st Quarter 2008	2nd Quarter 2008	3rd Quarter 2008	4th Quarter 2008
Revenue	$ 48.0	$ 54.2	$ 55.1	$ 56.5
Net earnings / (loss)	(1.6)	8.0	(4.4)	(21.1)
Net earnings / (loss) per trust unit	(0.02)	0.10	(0.06)	(0.27)
Total Assets	948.5	950.0	962.7	978.5
Long term debt*	460.6	469.6	460.9	462.9
Distribution per trust unit	0.23	0.23	0.23	0.06

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

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

Quarterly revenues have fluctuated between $43.4 million and $56.5 million over the prior two year period. A number of factors impact quarterly results including seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the significant fluctuation in the strength of the Canadian dollar which has resulted in significant changes in reported revenue from U.S. operations.

Quarterly net earnings have fluctuated between net earnings of $15.3 million and a net loss of $21.1 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as future tax expense due to the enactment of Bill C-52 and gains and losses on financial instruments due to APUC's adoption of Section 3855 and the discontinuation of hedge accounting under Section 3865.

Changes in Accounting Policies

APUC's accounting policies are described in Note 1 to the Consolidated Financial Statements for the period ended December 31, 2009. There have been no changes to the critical accounting policies as disclosed in APUC's audited Consolidated Financial Statements for the period ended December 31, 2008 except as disclosed below.

Goodwill and intangible assets

Effective January 1, 2009, APUC has adopted the CICA Handbook Section 3064, Goodwill and intangible assets. Section 3064 states that upon their initial identification, intangible assets are to be recognized as assets only if they meet the definition of an intangible asset and the recognition criteria. This section also provides further information on the recognition of internally generated intangible assets. As for subsequent measurement of intangible assets, goodwill, and disclosure, Section 3064 carries forward the requirements of the old Section 3062, Goodwill and Other Intangible Assets.

Accounting for the effects of certain types of regulation

Effective October 1, 2009, APUC retrospectively adopted rate regulated accounting for its Liberty Water utilities following the principle 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 Canadian GAAP for non-regulated entities are recorded. Regulatory assets and liabilities 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. Items to which regulatory accounting requirements apply include deferred rate case costs, and equity return component on regulated capital projects.

Deferred rate case costs relate to costs incurred by Liberty Water's utilities to file, prosecute and defend rate case applications and which the utility expects to receive prospective recovery through its rates approved by the regulators. Under ASC 980 these costs are capitalized and amortized over the period of rate recovery granted by the regulator while they are expensed under Canadian GAAP for non-regulated entities.

Under ASC 980, allowance for funds used during construction projects 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. It 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). Prior to the adoption of ASC 980, APUC capitalized interest costs directly attributable to the construction of these assets but did not capitalize the allowance for equity funds used during constructions.

The effect of adopting rate regulated accounting on previously reported amounts is as follows:

	Year-ended December 31, 2008		
	Balance as previously reported	Adjustment	Balance as restated
Other assets	971	1,053	2,024
Property plant and equipment	804,965	385	805,350
Future tax asset	3,304	(410)	2,894
Future income tax liability	85,654	150	85,804
Deficit	(359,547)	878	(358,669)

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

Effective January 1, 2009, APUC adopted EIC 173, Credit Risk and Fair Value of Financial Assets and Financial Liabilities, which clarifies that the credit risk of counterparties should be taken into account in determining the fair value of derivative instruments. EIC 173 has been applied retrospectively without restatement of prior periods to all financial assets and liabilities measured at fair value. The impact of adopting EIC 173 was a decline of $2,542 to the recorded amount of the financial derivative liability and an increase of $494 in future income tax liability at December 31, 2008 and a $2,048 decrease in deficit.

Business Combinations

In January 2009, the CICA issued Handbook Section 1582, Business combinations, which replaces the existing standards. This section establishes the standards for the accounting of business combinations, and states that all assets and liabilities of an acquired business will be recorded at fair value. Estimated obligations for contingent considerations and contingencies will also be recorded at fair value at the acquisition date. The standard also states that acquisition-related costs will be expensed as incurred and

that restructuring charges will be expensed in the periods after the acquisition date. This standard is equivalent to the International Financial Reporting Standards on business combinations. This standard is applied prospectively to business combinations with acquisition dates on or after January 1, 2011. Earlier adoption is permitted. APUC is currently evaluating the impact of adopting this standard on its consolidated financial statements.

Non Controlling Interests

In January 2009, the CICA issued Handbook Section 1602, Non-controlling interests, which establishes standards for the accounting of non-controlling interests of a subsidiary in the preparation of consolidated financial statements subsequent to a business combination. This standard is equivalent to the International Financial Reporting Standards on consolidated and separate financial statements. This standard is effective for 2011. Earlier adoption is permitted. APUC is currently evaluating the impact of adopting this standard on its consolidated financial statements.

Consolidated Financial Statements

In January 2009, the CICA issued Handbook Section 1601, consolidated financial statements, which replaces the existing standards. This section establishes the standards for preparing consolidated financial statements and is effective for 2011. Earlier adoption is permitted. APUC is currently evaluating the impact of adopting this standard on its consolidated financial statements.

Changeover to International Financial Reporting Standards

In 2011, APUC is required to change the accounting framework under which financial statements are prepared in Canada to International Financial Reporting Standards ("IFRS"). For the quarter ended March 31, 2011, APUC will report quarterly comparative financial information using IFRS. While the exact impact on APUC's financial statements of moving to IFRS is not completely known at this time; APUC conducted a high level diagnostic and qualitative assessment of its operations in order to identify the main areas where IFRS conversion will have the largest impact. Based on the analysis to date, areas of potential change may involve the valuation of property, plant and equipment, business combinations, translation of financial statements of foreign operations, income taxes, financial statement disclosure and initial adoption of IFRS under the provisions of IFRS 1, First-Time Adoption of IFRS. Experience in other jurisdictions has shown that earnings may tend to become more volatile and there will be an increase in the volume and complexity of financial disclosures.

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

Financial Statement preparation

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

Property, Plant & Equipment ("PP&E")

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

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

IFRS requires PP&E to be measured at cost in accordance with IFRS, breaking down material items into components and amortizing each one separately. This method of componentizing PP&E may result in an increase number of component parts for the power generation facilities that are separately recorded and depreciated and, as a result, may impact the calculation of depreciation expense. Libery Water already follows component accounting under Canadian GAAP. Significant progress has been made in this area, although the work is not yet completed.

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

In July 2009, the International Accounting Standards Board ("IASB") issued an exposure draft providing guidance on accounting for rate-regulated activities. In light of the responses received on the exposure draft, the IASB decided to further analyze the technical merits as to whether regulatory assets and regulatory liabilities can be recognized in accordance with the Conceptual Framework and to provide a revised project timeline when their analysis is completed. This revised approach, will likely result in Canadian utilities such as APUC having to convert to IFRS before an IFRS standard for rate-regulated activities is finalized, if any. In this context, the IASB tentatively decided to approve an IFRS 1 exemption which would allow Liberty Water to use the carrying amount of PP&E as its deemed cost at the date of transition to IFRSs.

Impairment of long-lived assets

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

Translation of foreign currency operations

IFRS does not have the same concept of self-sustaining or integrated operations, as under Canadian GAAP. IFRS requires each entity to determine its functional currency using a hierarchy of criteria. Under Canadian GAAP, the power generation facilities operating in the U.S. are considered integrated operations and translated into Canadian dollars using the temporal method whereby current rates of exchange are used for monetary assets and liabilities, historical rates of exchange for non-monetary assets and liabilities and average rates of exchange for revenues and expenses, except amortization which is translated at the rates of exchange applicable to the related assets. Gains and losses resulting from these translation adjustments are included in income. Under IFRS, APUC expects that its U.S.

operations will all be considered to have a U.S. dollar functional currency. The assets and liabilities of these operations will be translated into Canadian dollars at the rate prevailing at the balance sheet date while revenues and expenses to be converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the operations of self-sustaining operations will be reported as a component of Other Comprehensive Income in the Consolidated Statement of Comprehensive Income.

APUC also intends to avail itself of the IFRS 1 exemption to reset its foreign currency translation account to nil by transferring the amount to retained earnings on transition.

Business combinations

No significant immediate impact on the financial statements is anticipated on adoption of IFRS as APUC expects to take advantage of the IFRS 1 exemption which avoids the requirement to retrospectively restate all business combinations prior to the date of transition to IFRS, subject to certain balance sheet adjustments. Going forward, a number of differences between IFRS and Canadian GAAP will affect APUC's business acquisitions. Under IFRS, all assets and liabilities of an acquired business are recorded at fair value. Estimated obligations for contingent considerations and contingencies are also recorded at fair value at the acquisition date. In addition, acquisition-related costs are expensed as incurred. Under Canadian GAAP, acquisition-related costs form part of the consideration paid for the acquisition and contingent considerations are recorded as part of the cost of the acquisition when the contingency is resolved and the consideration is issued or becomes issuable.

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

Financial reporting expertise

APUC hired subject matter experts to co-ordinate, manage and execute the changeover process. APUC's key personnel and Audit Committee members have received and will continue to invest in various training courses with regards to IFRS rules and the impact it will have on APUC's reporting requirements. Internal training will be developed for accounting employees involved with the implementation as well as employees in the operating facilities whose processes and procedures will be affected by IFRS.

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

Information systems

APUC is reviewing the needs for systems upgrades and modifications. However, APUC does not expect combining the IFRS conversion with major IT system conversion.

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

Internal controls

The Internal Control group is involved every step of the way in the assessment of changes. Investor relations will be updated once the impacts of the transition to IFRS are better understood which will most likely be sometime in 2010 or 2011.

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

Business matters

APUC's senior secured revolving operating and acquisition credit facilities mature on January, 14, 2011. Accordingly, APUC will be in a position to review and amend any financial covenants impacted by IFRS during the renewal process.

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

Exhibit 99.4

Reconciliation with United States Generally Accepted Accounting Principles
ALGONQUIN POWER & UTILITIES CORP
For the year ended December 31, 2009 and 2008



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AUDITORS' REPORT ON RECONCILIATION WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN THE UNITED STATES

To the Board of Directors of Algonquin Power & Utilities Corp (formerly Algonquin Power Income Fund).

Under the date of March 23, 2010, we have reported on the consolidated balance sheets of Algonquin Power & Utilities Corp., (the "Company") as at December 31, 2009 and 2008 and the consolidated statements of operations, cash flows, deficit, comprehensive income/(loss) and accumulated other comprehensive income / (loss), for each of the years then ended, which are included in the Form 40-F. In connection with our audits of the aforementioned consolidated financial statements, we have audited the related supplemental note entitled "Reconciliation with United States Generally Accepted Accounting Principles" included in the Form 40-F. This supplemental note is the responsibility of the Company's management. Our responsibility is to express an opinion on this supplemental note based on our audits.

In our opinion, such supplemental note, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 23, 2010

ALGONQUIN POWER & UTILITIES CORP
Reconciliation with United States Generally Accepted Accounting Principles
(in thousands of Canadian dollars unless noted otherwise, except for per unit and per share amounts)

Algonquin Power & Utilities Corp ("APUC" or the "Company") follows generally accepted accounting principles in Canada (Canadian GAAP), which differs in certain material respects from accounting principles in the United States and from practices prescribed by the United States Securities and Exchange Commission (U.S. GAAP). The following information should be read in conjunction with the Company's 2009 audited consolidated financial statements prepared in accordance with Canadian GAAP.

Reconciliation of net earnings under Canadian GAAP to U.S. GAAP

	Year ended December 31,	
	2009	2008 Restated (note 1(f))
Net earnings / (loss), Canadian GAAP	$ 31,257	$ (19,038)
Adjustments, net of tax of $991 (2008 - $(510))	—	—
Convertible debentures (b), (d)	(1,850)	32
Non controlling interest (c)	2,251	(3,429)
Regulatory assets (f)	—	—
Deferred transaction costs (g)	(1,106)	—
Financial instruments (h)	—	2,432
Total adjustments	(705)	(965)
Net earnings / (loss), U.S. GAAP	30,552	(20,003)
Other comprehensive income/(loss), Canadian and U.S. GAAP	(27,270)	22,448
Total comprehensive income / (loss), U.S. GAAP	3,282	2,445
Basic net earnings / (loss) per share	$ 0.38	$ (0.27)
Diluted net earnings / (loss) per share	$ 0.38	$ (0.26)

The application of U.S. GAAP results in differences to the following balance sheet items:

	December 31, 2009		December 31, 2008	
	Canadian GAAP	U.S. GAAP	Canadian GAAP Restated (note 1(f))	U.S. GAAP
Property, plant and equipment (f)	$ 749,350	$ 749,350	$ 805,350	$ 805,350
Other assets -regulatory assets (f)	1,713	1,713	1,053	1,053
Other assets -deferred transaction costs (g)	1,474	0	0	0
Deferred financing costs (b*(iii)*), (e)	200	6,001	243	4,667
Long-term liabilities (e)	244,772	244,970	296,825	297,089
Convertible debentures (b *(iii)*), (e), (d)	173,257	185,600	140,427	144,964
Future income tax liability (i)	80,827	79,879	86,995	87,522
Derivative liabilities (h)	9,695	9,695	33,554	31,012
Non controlling interest (c)	0	0	12,548	0
Temporary equity (a), (c)	0	0	0	740,765
Additional paid-in-capital (b *(ii)*)	0	1,487	0	0
Shareholders' capital (a), (b), (c), (d)	787,037	785,827	722,215	0
Deficit	(344,676)	(352,219)	(358,669)	(363,033)

Reconciliation of deficit under Canadian GAAP to U.S. GAAP

	As at December 31,	
	2009	2008 Restated (note 1(f))
Deficit, Canadian GAAP	$(344,676)	$ (358,669)
Adjustments, net of tax		
Convertible debentures (b), (d)	(1,883)	70
Non controlling interest (c)	(4,554)	(6,482)
Regulatory assets (f)	—	—
Deferred transaction costs (g)	(1,106)	—
Financial instruments (h)	—	2,048
Total adjustments	(7,543)	(4,364)
Deficit, U.S. GAAP	$(352,219)	$ (363,033)

ALGONQUIN POWER & UTILITIES CORP
Reconciliation with United States Generally Accepted Accounting Principles
(in thousands of Canadian dollars unless noted otherwise, except for per unit and per share amounts)

1. Description of significant differences

a) Unit Exchange Offer

On October 27, 2009, Algonquin Power Income Fund (the "Fund") completed a reverse take-over transaction (the "Transaction") of Hydrogenics Corporation ("Hydrogenics") which resulted in the Fund's Unitholders becoming shareholders in Hydrogenics which was immediately renamed Algonquin Power & Utilities Corp. As a result, the Fund itself became a wholly owned subsidiary of APUC. For Canadian and U.S. GAAP purposes, APUC is considered a continuation of the Fund except for the legal capital of the Fund which is adjusted to reflect the legal capital of APUC.

Prior to the Transaction, the Fund's trust units contained a redemption feature which was required for the Fund to retain its Canadian mutual fund trust status. For Canadian GAAP purposes, the Trust units were considered permanent equity and were presented as a component of Unitholders' equity. Under U.S. GAAP, equity with a redemption feature is presented outside of permanent equity, as temporary equity between the liability and equity sections of the balance sheet. As such, in the prior year, the trust units of $721,736 were reclassed from permanent equity to temporary equity for U.S. GAAP purposes.

b) CD Exchange Offer

Contemporaneously with the Unit Exchange Offer a convertible debenture exchange offer (the "CD Exchange Offer") was made by APUC to debentureholders of the Fund.

(i) Similar to Canadian GAAP, under U.S. GAAP the change in coupon rates and maturity terms of the convertible debentures under the CD Exchange Offer is considered to be a debt modification and not an extinguishment under accounting standards based on the Company's evaluation of the changes in cash flows and fair value of the conversion options under the terms of the revised debt agreements. The consolidated balance sheet of APUC under Canadian GAAP reflects the convertible debentures at their original carrying values, net of an allocation of transaction costs of approximately $2,544 associated with the CD Exchange Offers. Under U.S. GAAP these transaction costs of $2,544 are expensed as incurred since the costs are paid to third parties and not the debtor. This results in a reduction of $53 effective interest on convertible debentures under U.S. GAAP in comparison to Canadian GAAP.

(ii) The change in conversion price of the Series 1 and Series 2 convertible debentures under the CD Exchange Offer results in a fair value of the conversion feature of $1,179 and $308, respectively. Under U.S. GAAP, the combined fair value of the conversion feature of $1,487 is recorded as a discount on debt, with an offsetting entry to additional paid-in-capital. Under Canadian GAAP, the offsetting entry is recorded in equity. An adjustment of $1,487 reflects the reclassification of conversion feature recorded as equity under Canadian GAAP to additional paid-in capital under U.S. GAAP.

(iii) Under U.S. GAAP the adjustment for the conversion of $21,209 of the Series 1 convertible debentures into common shares does not result in any Canadian GAAP difference.

However, under Canadian GAAP the pro rata share of existing deferred financing charges associated with the Series I debentures of $306 is recorded as a charge against equity upon conversion of $21,209 of debentures into common shares, with a corresponding adjustment to convertible debentures. Under U.S. GAAP, the same net amount is charged against equity however, the corresponding adjustment of $306 is made to deferred financing costs to reflect the different classification of deferred charges for Canadian and U.S. GAAP purposes.

c) Non controlling interest

Exchangeable units ("AirSource Exchangeable Units") were issued by Algonquin (AirSource) Power LP ("Algonquin AirSource"), a subsidiary of the Fund, when Algonquin AirSource acquired AirSource Power Fund I LP on June 29, 2006. The AirSource Exchangeable Units entitled the holders to receive distributions which are equivalent to the Fund's distributions, as long as the facility which was acquired upon acquisition of AirSource generated adequate cash flows.

Under Canadian GAAP the AirSource Exchangeable Units were recorded in the Company's consolidated financial statements as "Non controlling interest". The portion of income or loss attributable to this non controlling interest and distributions to holders of the exchangeable units are recorded as a reduction to the carrying amount of the non controlling interest. Under U.S. GAAP the AirSource Exchangeable Units are classified along with the Trust Units outside of permanent equity as temporary equity since they are able to be converted at the holder's option to the Fund's Trust Units. The temporary equity was initially recorded at an amount equal to the redemption value based on the terms of the AirSource Exchangeable Units. Any increase in the redemption value of the AirSource Exchangeable Units is recorded as an adjustment through deficit and any downward adjustment is restricted only to the extent of previously recorded increases in the carrying amount arising from such adjustments. No adjustment was required to the carrying amount of the AirSource Exchangeable Units in temporary equity. Under U.S. GAAP the proportion of income attributable to the AirSource Exchangeable Units non controlling interest of $2,251 in 2009 and proportion of loss attributable to the AirSource Exchangeable Units non controlling interest of $3,429 in 2008, respectively is recorded to deficit rather than through earnings and distributions to the AirSource Exchangeable Unit holders of $323 in 2009 and $2,399 in 2008 are recorded as a charge to deficit.

On December 31, 2009, all remaining Air Source units were converted to APUC shares. Under both Canadian and U.S. GAAP, when the AirSource Exchangeable Units are converted to shares, the non controlling interest (temporary equity under U.S. GAAP) on the consolidated balance sheet is reduced on a pro-rata basis together with a corresponding increase in shares. However, since the carrying amount of the non-controlling interest per Canadian GAAP differs from the carrying amount in temporary equity per U.S. GAAP, the amount transferred to shareholders' capital differs by $4,554.

d) Convertible debentures

Under Canadian GAAP, the fair value of the convertible debentures was bifurcated into equity (the conversion option) and debt whereas under U.S. GAAP, the convertible debentures do not have the features that would require bifurcation. Accordingly, an adjustment of $4,275 in relation to the Series 3 ($479 in relations to the Series 2 in 2008) reflects the reclassification of the value attributed to the equity components recorded under Canadian GAAP to convertible debentures in the consolidated balance sheet at December 31, 2009.

Under Canadian GAAP, the accretion of the residual carrying value of the convertible debentures to the face value of the convertible debentures over the life of the instrument is charged to operations. Under U.S. GAAP, no such accretion is required if the conversion feature is not required to be bifurcated. This GAAP difference resulted in a reversal of accretion of $27 recorded under Canadian GAAP at December 31, 2009 ($32 in 2008).

e) Financing costs

The Company records financing costs as a reduction to long-term liabilities and convertible debentures under Canadian GAAP. Under U.S. GAAP, such costs are presented in assets as deferred financing costs. Accordingly, the adjustment reflects a cumulative increase of $197 in long-term liabilities ($264 in 2008) and $5,604 ($4,160 in 2008) in convertible debentures with a corresponding increase in deferred financing costs of $5,801 ($4,424 in 2008).

f) Regulated Operations

The Company's utility operations are subject to regulation by the public utility commissions of the states in which they operate. Under U.S. GAAP, the Fund's utility operations follow the regulatory accounting principles prescribed under Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Effective October 1, 2009, APUC retrospectively adopted ASC 980 for Canadian GAAP, eliminating related GAAP differences.

g) Business combinations

Under Canadian GAAP, the Company recorded $1,474 of deferred transaction costs in connection with future acquisitions. Under U.S. GAAP, the Company adopted ASC 805 Business combinations prospectively effective January 1, 2009 for business combinations with acquisition dates on or after January 1, 2009. Under U.S. GAAP, acquisition-related costs are expensed as incurred.

h) Fair value measurement

Under U.S. GAAP, ASC 820 ("SFAS") No. 157, Fair Value Measurements, establishes a definition and a framework for measuring fair value, expands disclosures about fair value measurements, and provides guidance on how to measure fair value by providing a fair value hierarchy to classify the source of fair value information. The standard also clarifies that the credit risk of counterparties should be taken into account in determining the fair value. Under Canadian GAAP, the Company adopted EIC 173, Credit Risk and Fair Value of Financial Assets and Financial Liabilities, effective January 1, 2009. Under U.S GAAP, ASC 820 is required to be adopted effective January 1, 2008. The adjustment of $3,002 reflects the change in credit risk on derivative financial instruments of the Company for the year ended December 31, 2008.

i) Income taxes

The adjustments reflect the future tax impact of the above U.S. GAAP adjustments.

j) Cash flow statement

The consolidated cash flow statement prepared in accordance with Canadian GAAP presents substantially the same information that is required under U.S. GAAP with the exception of deferred transaction costs in connection with future acquisitions of $1,474 as described in note g) which under U.S. GAAP is classified as cash used in operating activities unlike in Canadian GAAP where it is classified as investing activity.

k) Recently issued accounting pronouncements not yet adopted

Revenue recognition:

In October 2009, the FASB issued ASU 2009-13, Revenue Recognition (Topic 605): Multiple-Deliverable Revenue Arrangements—a consensus of the FASB Emerging Issues Task Force ("ASU 2009-13"). ASU 2009-13 requires entities to allocate revenue in an arrangement using estimated selling prices of the delivered goods and services based on a selling price hierarchy. The ASU eliminates the residual method of revenue allocation and requires revenue to be allocated using the relative selling price method. ASU 2009-13 should be applied on a prospective basis for revenue arrangements entered into or materially modified in fiscal years beginning on or after June 15, 2010, with early adoption permitted. The Company does not expect adoption of ASU 2009-13 to have a material impact on the Company's consolidated financial statements.

Exhibit 99.5



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CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Algonquin Power & Utilities Corp

We consent to the inclusion in this annual report on Form 40-F of:

- our auditors' report dated March 23, 2010 on the consolidated balance sheets of Algonquin Power & Utilities Corp. ("the Company") as at December 31, 2009 and 2008, and the consolidated statements of earnings, retained earnings, comprehensive income/(loss) and cash flows for each of the years then ended
- our Comments by Auditors for US Readers on Canada-US Reporting Differences, dated March 23, 2010
- our auditors' report on reconciliation with generally accepted accounting principles in the United States dated March 23, 2010

each of which is contained in this annual report on Form 40-F of the Company for the fiscal year ended December 31, 2009.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 26, 2010

KPMG LLP, is a Canadian limited liability partnership and a member firm of the KPMG Network of independent member firms affiliated with KPMG International, a Swiss cooperative. KPMG Canada provides services to KPMG LLP.

Exhibit 99.6

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 31, 2010

By: /s/ Ian E. Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

Exhibit 99.7

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 31, 2010

By: /s/ David Bronicheski
Name: David Bronicheski
Title: Chief Financial 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, 2009 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 31, 2010

By: /s/ Ian E. Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

Exhibit 99.9

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, 2009 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 31, 2010

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