2008

# Algonquin Power Income Fund

## Annual Financial Results

ALGONQUIN POWER

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# MANAGEMENT'S DISCUSSION AND ANALYSIS

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

Algonquin Power Income Fund ("Algonquin" or the "Company") has prepared the following discussion and analysis to provide information to assist its unitholders' understanding of the financial results for the three and twelve months ended December 31, 2008. This discussion and analysis should be read in conjunction with Algonquin's audited consolidated financial statements for the years ended December 31, 2008 and 2007 and the notes thereto. This material is available on SEDAR at www.sedar.com and on the Algonquin website at www.AlgonquinPower.com. Additional information about the Company, including the Annual Information Form for the year ended December 31, 2008 can be found on SEDAR at www.sedar.com.

This Management's Discussion and Analysis ("MD&A") is based on information available to management as of March 5, 2009.

## 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 Algonquin and Algonquin Power Management Inc. ("APMI"), the entity which provides management services to Algonquin (including advice and consultation concerning business planning, support, guidance and policy making) with respect to future events, based upon assumptions relating to, among others, the performance of the Company'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 the Company, its future plans and its distributions to unitholders. 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 us to make assumptions and involve inherent risks and uncertainties. Algonquin and APMI caution that although we believe our 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 taxation of income funds; and the state of the Canadian and the United States ("U.S.") economy and accompanying business climate. Algonquin and APMI caution that this list is not exhaustive, and other factors could adversely affect our results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. The Company reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. Although Algonquin and APMI believe 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 the dates hereof. Algonquin and APMI are not obligated nor do either of them 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 "cash available for distribution", "cash available for distribution after growth and maintenance capital expenditures", and "earnings before interest, taxes, depreciation and amortization" ("EBITDA") are used throughout this MD&A. The terms "cash available for distribution", "cash available for distribution after growth and maintenance capital expenditures" and EBITDA are not recognized measures under Canadian generally accepted accounting principles ("GAAP"). There is no standardized measure of "cash available for distribution", "cash available for distribution after growth and maintenance capital expenditures" and EBITDA, consequently Algonquin's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "cash available for distribution", "cash available for distribution after growth and maintenance capital expenditures" and EBITDA can be found throughout this MD&A. EBITDA is a metric used by many investors to compare companies on the basis of ability to generate cash from operations. Algonquin uses these calculations to monitor the amount of cash generated by Algonquin as compared to the amount of cash distributed by Algonquin. Algonquin uses EBITDA to assess the operating performance of the Company without the effects of depreciation and amortization expense which are derived from a number of non-operating factors, accounting methods and assumptions. APMI believes that presentation of this measure will enhance an investor's understanding of Algonquin's operating performance. EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

## Overview

Algonquin is a company that owns and has interests in a diverse portfolio of clean, renewable power generation and sustainable infrastructure assets across North America, including 42 renewable energy facilities, 11 thermal energy facilities, and 17 water distribution and waste-water facilities. Algonquin Power was established in 1997 and produces stable earnings through a diversified portfolio of renewable energy and utility assets.

Algonquin 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. The company also owns a 99 MW wind farm in Manitoba. The renewable energy facilities are generally facilities operating under power purchase agreements with major utilities that have an average remaining life of 18 years. The Company's 11 thermal energy facilities also operate under power purchase agreements with an average remaining contract length of 10 years with a combined generating capacity of 320 MW. The Company's Utility Services business unit owns 17 regulated utilities in the United States of America providing water and wastewater services in the states of Arizona, Texas, Missouri and Illinois. 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

Algonquin's business strategy is to maximize long term unitholder value by strengthening its position as a strong renewable energy and infrastructure company. The Company is focused on growth in cash flow and earnings in the business segments in which it operates. Algonquin currently makes monthly cash distributions to unitholders of $0.02 per trust unit per month or $0.24 per trust unit per annum. This sustainable level of cash distributions allows for both an immediate return on investment for unitholders and retention of sufficient cash to fund growth opportunities, fund anticipated tax liabilities when the new tax policies affecting income trusts are implemented, and mitigate the impact of volatility in foreign exchange.

Algonquin's operations are aligned into two major business units: *Power Generation & Development*, and *Utility Services*. The two business units reflect the Company's business strategy to be a leading provider of essential services and how Algonquin manages its business and classifies its operations for planning and measuring performance.

The Power Generation & Development business unit develops and operates a diversified portfolio of electrical energy generation facilities. Within this business unit there are three distinct divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops Algonquin's greenfield power generation projects, pursues accretive acquisitions of electrical energy generation facilities as well as development of organic growth opportunities within Algonquin's existing portfolio of renewable energy and thermal energy facilities. The renewable power and thermal energy generation business of Algonquin is managed with an emphasis on growth through the development of green-field projects and opportunities within Algonquin's existing portfolio. This involves building on the Company's expertise in the origination of greenfield renewable energy projects, building upon the Company's existing portfolio of assets for further growth, and capitalizing on opportunities that may emerge in the current turbulence of the capital markets.

The Utility Services business unit provides safe, reliable transportation and delivery of water and waste-water treatment in its service area and pursues accretive water and waste-water utility acquisition opportunities. Building on its experience in the regulated water utility sector, Utility Services is also considering expanding its operations into other regulated essential utilities such as natural gas distribution and electricity distribution.

## Annual results from operations

### Key Selected Annual Financial Information

| | Year ended December 31 | | |
|---|---|---|---|
| | **2008** | **2007** | **2006** |
| Revenue [1] | **$ 213,796** | $ 186,175 | $ 193,244 |
| EBITDA [3] | **$ 90,028** | $ 86,169 | $ 92,038 |
| Cash provided by operating activities | **66,874** | 40,427 | 69,332 |
| Net earnings (Loss) from continuing operations | **(19,038)** | 24,763 | 30,728 |
| Net earnings (Loss) | **(19,038)** | 23,671 | 27,956 |
| Distribution to Unitholders [2] | **57,755** | 69,923 | 66,957 |
| Per trust unit | | | |
| Net earnings (Loss) from continuing operations | **(0.25)** | 0.34 | 0.43 |
| Net earnings (Loss) | **(0.25)** | 0.32 | 0.39 |
| Diluted net earnings (loss) | **(0.25)** | 0.31 | 0.39 |
| Cash provided by Operating Activities [4] | **0.86** | 0.53 | 0.95 |
| Distribution to Unitholders | **0.75** | 0.92 | 0.92 |
| Total Assets | **978,130** | 954,067 | 1,048,324 |
| Long Term Debt | **293,590** | 281,725 | 229,006 |

[1] Prior period comparative amounts have been adjusted due to the classification of certain landfill-gas and New England hydroelectric facilities sold during the 2007 fiscal year as Discontinued Operations.
[2] Includes distributions to non-controlling interest.
[3] Non-GAAP measurement, see "Reconciliation of EBITDA to net earnings" in this MD&A.
[4] The change in cash provided by operating activities in the twelve months ended December 31, 2008 is primarily due to increased cash from operations and increased cash from working capital balances primarily in relation to final payments to Vestas regarding the achievement of commercial operation at the St. Leon facility in the prior year.

For the year ended December 31, 2008, Algonquin reported total revenue of $213.8 million as compared to $186.2 million during the same period in 2007, a $27.6 million or 14.8% increase. The increase in revenue from energy sales in 2008 as compared to the same period in 2007 was primarily the result of an increase of $8.5 million due to a combination of higher energy production and increased weighted average energy rates generated in the Renewable Energy division, $1.5 million in Utility Services due to rate increases combined with organic growth at existing facilities, and an increase of $11.3 million due to a combination of changes in production and average energy rates at the Sanger and Windsor Locks facilities in the Thermal Energy division as compared to the prior year. A more detailed analysis of these factors is presented within the business unit analysis.

For the year ended December 31, 2008, the Company experienced an average U.S. exchange rate of approximately $1.067 as compared to $1.074 in the same period in 2007. As such, any year over year variance in revenue or expenses, in local currency, at any of Algonquin's U.S. entities may be affected by a change in the average exchange rate, upon conversion to Algonquin'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, Algonquin has foreign exchange forward contracts in place, which partially mitigate the impact on cash available for distribution (see Risk Management – Currency Fluctuations).

EBITDA in the year ended December 31, 2008 increased by $3.8 million to $90.0 million compared to $86.2 million in the same period in 2007, an increase of 4.4%. The increase in EBITDA is primarily related to increased earnings from operations of $6.5 million due to improved hydrological conditions and higher gas prices at the co-generation facilities, partially offset by decreased interest, dividend and other income of $2.4 million due to lower gains on sale of certain fixed assets than in the comparative period. The prior period included a non-recurring reduction in operating expenses related to the achievement of commercial operation at the St. Leon facility, the recognition of interest income earned on unpaid liquidated damages at the St. Leon facility totaling approximately $2.1 million and a termination fee of $1.75 million earned in connection with Algonquin's offer to purchase the outstanding units of Clean Power Income Fund ("CPIF") included in the comparative period.

For the year ended December 31, 2008, net loss from continuing operations totalled $19.0 million as compared to net earnings of $24.8 million during the same period in 2007. The decrease in net earnings as compared to

2007 was primarily the result of unrealized losses on financial instruments resulting from changes in foreign exchange rates and unrealized losses on financial instruments resulting from changes in interest rates.

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 losses of derivative financial instruments:

| | Year ended December 31 | | |
|---|---|---|---|
| | **2008** | **2007** | **Change** |
| **Foreign Exchange Contracts:** | | | |
| Unrealized mark to market loss/(gain) on derivative financial instruments | **$ 25,473** | $ (6,950) | **$ 32,424** |
| Realized loss/(gain) on derivative financial instruments | **(5,077)** | (9,540) | **4,463** |
| | **$ 20,396** | $ (16,490) | **$ 36,887** |
| **Interest Rate Swap Contracts:** | | | |
| Unrealized mark to market loss/(gain) on derivative financial instruments | **$ 16,953** | $ 2,088 | **$ 14,865** |
| Realized loss/(gain) on derivative financial instruments | **399** | (67) | **466** |
| | **$ 17,352** | $ 2,021 | **$ 15,331** |
| **Derivative Financial Instruments Total:** | | | |
| Unrealized mark to market loss/(gain) on derivative financial instruments | **$ 42,426** | (4,862) | **$ 47,289** |
| Realized loss/(gain) on derivative financial instruments | **(4,678)** | (9,607) | **$ 4,929** |
| Total loss/(gain) on derivative financial instruments | **$ 37,748** | **$ (14,469)** | **$ 52,218** |

In addition, the earnings from continuing operations declined $11.7 million due to foreign exchange loss primarily resulting from unrealized gains or losses on U.S. dollar denominated debt, $2.4 million due to lower earnings on portfolio investments and lower gains on the sale of assets, $2.2 million due to increased amortization expense, and $52.2 million due to reduced realized gains on derivative financial instruments contracts settled in the period and increased unrealized mark to market losses on derivative financial instruments, as a result of reduced interest rates and the weaker Canadian dollar. These items were partially offset by $6.5 million in increased earnings from operating facilities, $0.3 million of reduced interest expense due to decreased average borrowings and lower rates on Algonquin's variable interest rate debt booked in the period, $2.7 million resulting from increased non-cash minority interest losses at the St. Leon facility primarily due to unrealized losses on interest rate swap contracts booked in the year and a $14.8 million reduction in current and future income taxes due to the impact of bonus depreciation in the U.S. and the reduction of future tax expense resulting from unrealized mark to market losses on derivative instruments.

In the comparative period, Algonquin recorded a $27.9 million future income tax expense in order to recognize the effect of future taxes being imposed by the federal government beginning in 2011 on certain publicly traded income trusts including Algonquin enacted through Bill C-52 on June 22, 2007 (see Risk Management – Changes to income tax laws).

The comparative period also includes a termination fee of $1.8 million earned in connection with Algonquin's offer to purchase the outstanding units of CPIF and interest income earned by the St. Leon facility, both of which were not earned in the current period. In addition, the comparative period includes a $0.7 million write down of notes receivable.

Net loss from continuing operations totalled $19.0 million for the year ended December 31, 2008 as compared to a net income of $24.8 million during the same period in 2007. Net loss from continuing operations per trust unit totalled $0.25 for the year ended December 31, 2008 as compared to net earnings of $0.34 per trust unit during the same period in 2007.

During the year ended December 31, 2008, cash provided by operating activities totalled $66.9 million or $0.86 per trust unit as compared to cash provided by operating activities of $40.4 million, or $0.53 per trust unit during the same period in 2007. The change in cash provided by operating activities after changes in working capital in the year ended December 31, 2008, is primarily due to increased earnings from operations, increased net cash from trade accounts receivable and trade accounts payable, primarily in relation to final payments to Vestas regarding the achievement of commercial operation at the St. Leon facility in the prior year, partially offset by lower income from derivative financial instruments and increased current income tax expense as compared to the same period in 2007.

## Fourth quarter results from operations

### Key Selected Quarterly Financial Information

| | Three Months ended December 31 2008 | 2007 |
|---|---|---|
| Revenue [1] | **$ 56,505** | $ 44,317 |
| EBITDA [3] | **$ 23,256** | $ 18,476 |
| Cash provided by operating activities | **13,866** | (705) |
| Net earnings (Loss) from continuing operations | **(21,095)** | 7,475 |
| Net earnings (Loss) | **(21,095)** | 7,559 |
| Distribution to Unitholders [2] | **4,774** | 17,481 |
| Per trust unit | | |
| Net earnings (Loss) from continuing operations | **(0.27)** | 0.10 |
| Net earnings (Loss) | **(0.27)** | 0.11 |
| Diluted net earnings (loss) | **(0.27)** | 0.11 |
| Cash provided by Operating Activities [4] | **0.17** | (0.01) |
| Distribution to Unitholders | **0.06** | 0.23 |
| Total Assets | **978,130** | 954,067 |
| Long Term Debt | **293,590** | 281,725 |

[1] Prior period comparative amounts have been adjusted due to the classification of certain landfill-gas and New England hydroelectric facilities sold during the 2007 fiscal year as Discontinued Operations.
[2] Includes distributions to non-controlling interest.
[3] Non-GAAP measurement, see "Reconciliation of EBITDA to net earnings" in this MD&A.
[4] The change in cash provided by operating activities in the three months ended December 31, 2008 is primarily due to increased cash from operations and increased cash from working capital balances primarily in relation to final payments to Vestas regarding the achievement of commercial operation at the St. Leon facility in the prior year.

For the quarter ended December 31, 2008, Algonquin reported total revenue of $56.5 million as compared to $44.3 million during the same period in 2007, a $12.2 million or 27.5% increase. The increase in revenue from energy sales as compared to the same period of 2007 was primarily the result of an increase of $3.0 million due to a combination of higher energy production and increased weighted average energy rates generated in the Renewable Energy division and $2.4 million due to a combination of changes in production and average energy rates at the Sanger and Windsor Locks facilities in the Thermal Energy division as compared to the same period in the prior year. In addition, Algonquin reported increased revenue of $6.2 million from operations in the U.S. as a result of the weaker Canadian dollar. A more detailed analysis of these factors is presented within the business unit analysis.

For the three months ended December 31, 2008, the Company experienced an average U.S. exchange rate of approximately $1.212 as compared to $0.982 in the same period in 2007. As such, any quarterly variance in revenue or expenses, in local currency, at any of Algonquin's U.S. entities may be affected by a change in the average exchange rate, upon conversion to Algonquin'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, Algonquin has foreign exchange forward contracts in place, which partially mitigate the impact on cash available for distribution (see Risk Management – Currency Fluctuations).

EBITDA in the quarter ended December 31, 2008 increased by $4.7 million to $23.2 million as compared to $18.5 million in the same period in 2007, an increase of 25.4%. The increase in EBITDA is primarily related to increased earnings from operations of $3.5 million due to improved hydrological conditions and higher gas prices and increased interest, dividend and other income of $0.9 million due to gains on the sale of certain assets than in the comparative period.

For the quarter ended December 31, 2008, net loss from continuing operations totalled $21.1 million as compared to net earnings of $7.5 million during the same period in 2007. The decrease in net earnings as compared to the fourth quarter of 2007 was primarily the result of unrealized mark to market losses on derivative financial instruments resulting from changes in foreign exchange rates and unrealized mark to market losses on derivative financial instruments resulting from changes in interest rates.

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 losses of derivative financial instruments:

| | Three months ended December 31 | | |
|---|---|---|---|
| | 2008 | 2007 | Change |
| **Foreign Exchange Contracts:** | | | |
| Unrealized mark to market loss/(gain) on derivative financial instruments | **$ 17,583** | $ 1,770 | **$ 15,813** |
| Realized loss/(gain) on derivative financial instruments | **345** | (3,642) | **$ 3,987** |
| | **$ 18,198** | $ (1,872) | **$ 19,800** |
| **Interest Rate Swap Contracts:** | | | |
| Unrealized mark to market loss/(gain) on derivative financial instruments | **$ 13,058** | $ 1,752 | **$ 11,306** |
| Realized loss/(gain) on derivative financial instruments | **139** | (83) | **$ 222** |
| | **$ 13,197** | $ 1,669 | **$ 11,528** |
| **Derivative Financial Instruments Total:** | | | |
| Unrealized mark to market loss/(gain) on derivative financial instruments | **$ 30,641** | 3,522 | **$ 27,119** |
| Realized loss/(gain) on derivative financial instruments | **484** | (3,725) | **$ 4,209** |
| Total loss/(gain) on derivative financial instruments | **$ 31,125** | **$ ( 203)** | **$ 31,328** |

In addition, the earnings from continuing operations declined $3.0 million due to reduced realized foreign exchange gains primarily resulting from unrealized gains or losses on U.S. dollar denominated debt, $1.8 million due to increased amortization expense, and $31.3 million due to reduced realized gains on derivative financial instruments contracts settled in the period and increased unrealized mark to market losses on derivative financial instruments, as a result of reduced interest rates and the weaker Canadian dollar. These decreases were partially offset by $3.5 million in increased earnings from operations resulting from improved hydrological conditions and higher gas prices at the co-generation facilities, $2.7 million resulting from increased non-cash minority interest losses at the St. Leon facility primarily due to unrealized losses on interest rate swap contracts booked in the quarter, $1.2 million due to increased recovery of current and future income tax expenses, $0.9 million increased other income resulting from gains on the sale of certain assets, and $1.2 million due to lower interest expense resulting from lower interest rates on Algonquin's variable interest rate debt and interest expense capitalized on construction projects, primarily in Utility Services.

Net loss from continuing operations totalled $21.1 million for the three months ended December 31, 2008 as compared to net income of $7.5 million during the same period in 2007. Net loss from continuing operations per trust unit totalled $0.27 for the quarter ended December 31, 2008 as compared to net earnings of $0.10 per trust unit during the same period in 2007.

During the quarter ended December 31, 2008 cash provided by operating activities totalled $13.9 million or $0.17 per trust unit, as compared to cash used by operating activities of $0.7 million or $0.01 per trust unit during the same period in 2007. The change in cash provided by operating activities after changes in working capital in the quarter ended December 31, 2008 is primarily due to increased earnings from operations, increased cash from trade accounts receivable due to the timing of receipts and decreased use of cash from trade accounts payable, primarily in relation to final payments to Vestas regarding the achievement of commercial operation at the St. Leon facility in the prior year, partially offset by lower income from derivative financial instruments and increased current income tax expense as compared to the same period in 2007.

During the quarter ended December 31, 2008, the Company recorded distributions at $0.06 per trust unit, as compared to distributions of $0.23 per trust unit in the same period in 2007. During the year ended December

31, 2008, the Company recorded distributions at $0.75 per trust unit, as compared to distributions of $0.92 per trust unit in the same period in 2007.

## Major highlights in 2008

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

### Business Unit realignment

On October 20, 2008 the Board of Trustees approved a strategic plan that would align Algonquin's business structure with current market conditions and expected growth prospects. In order to strengthen Algonquin's financial position and support its strategic growth initiatives, the Company established a sustainable cash distribution level consistent with the Company's growth prospects. At the same time Algonquin announced that it would preserve the tax efficiency of the income trust structure through 2010 to further strengthen its financial position and support its growth initiatives. The income trust structure allows for the distribution to unitholders of cash generated within the trust without being taxed at the operating company level. In support of its strategic plan, Algonquin realigned its operations into two major business units: *Power Generation & Development*, and *Utility Services*. The two new business units better reflect the Company's business strategy to be a leading provider of essential services, while maximizing unitholder value through a combination of stable earnings, sustainable cash distributions and a risk profile consistent with top-quartile North American power generation and utility operations.

Algonquin will also be positioning the Utility Services business unit as an independent subsidiary during fiscal 2009 which will increase the business focus on best practices for utility management. Algonquin will establish a separate capital structure to permit new sources of debt and equity capital into the Utility Services business unit if the capital demands from its growth program outpace the funding capabilities of the business unit or the Company.

As part of the new strategic plan announced on October 20, 2008, it was also announced that it was the intention of the Trustees to effect an internalization of management with a target date by the end of the first quarter of 2009. Given the continuing and prolonged deterioration of the credit and capital markets, the target date will not be met. The decision of the Trustees to internalize management is being reviewed within the current credit and capital markets conditions.

### Highground Capital Corporation Acquisition

On August 1, 2008, Algonquin issued approximately 3.5 million trust units and has received to date total gross proceeds of $27.0 million or $7.69 per trust unit, which is above the $7.41 trading price of Algonquin units at the time of issue.

The unit issue was pursuant to an agreement entered into on June 27, 2008 between Algonquin, Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG"), which is the manager of Highground and a related party of Algonquin controlled by the shareholders of APMI. Under the agreement, CJIG acquired all of the issued and outstanding common shares of Highground, and Algonquin issued approximately 3.5 million trust units of which approximately 3.1 million trust units were received by Highground shareholders as part of the agreement, with the remaining trust units being retained by CJIG. Algonquin has recorded the 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 units being recorded at a value of $26.2 million. In connection with this transaction, Algonquin 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 Algonquin affiliates related to its St. Leon and Brampton Cogeneration LP ("BCI") projects; 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. Algonquin'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 Algonquin will be determined through negotiation between the trustees of Algonquin 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. Algonquin is entitled to 50% of the ultimate proceeds from these investments, after certain adjustments for transaction costs.

### Brampton Co-generation Project

In June 2008, the Brampton Co-generation Project was commissioned and operational. The project involved diverting the existing steam produced by the Algonquin Power Energy-from-Waste ("EFW") facility to a nearby recycled paper board manufacturing mill that requires approximately 90,000 pounds of steam per hour in its manufacturing activities. Algonquin established BCI to operate the required facilities to supply steam produced through normal operations at the EFW to this customer.

The project's total net investment was approximately $16.2 million and generated cash from operations of approximately $0.9 million in its first seven months of operation in fiscal 2008.

### Campbellford acquisition

On April 2, 2008, Algonquin acquired the remaining 50% interest in the Campbellford Partnership (the "Partnership") not already owned by the Company and now fully consolidates the Partnership in its financial statements. The Partnership owns a 4 megawatt hydroelectric generation station on the Trent River near Campbellford, Ontario. As a result, Algonquin's total investment in the Partnership now stands at $8.2 million. The Partnership has generated operating profit of $0.9 million annually over the prior three years.

### Credit agreement renewal

On January 16, 2008 Algonquin renewed its combined $175.0 million senior secured revolving operating and acquisition credit facilities (the "Facilities") with its Canadian bank syndicate. Under terms of the renewal, the Facilities are 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 facilities 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, Algonquin does not have any near term credit maturity exposures. By the end of 2008, the Company had exercised a portion of the accordion feature, resulting in total committed and available Facilities of $192.8 million.

### Completion of Utility Services major capital program

By the end of 2008, Algonquin completed the majority of its major capital program in the Utility Services business unit. With its major capital program now complete, Algonquin is initiating rate cases at several utilities. Based on the capital invested in utility rate base and the return on investment allowed by the regulatory bodies, the Company expects to increase annualized EBITDA by more than $10 million. The regulatory review of the rates and tariffs for these facilities are expected to conclude in the second half of 2009, with the new rates and tariffs going into effect between mid 2009 and the first half of 2010, depending on the state in which the facility operates.

## Outlook

The Power Generation & Development division is expecting a return to normal long term average resource conditions in 2009. Throughput at the EFW facility is expected to continue at levels experienced in 2008. The Windsor Locks and Sanger facilities are expected to continue to operate in 2009 in line with the Company's long term expectations. Algonquin's power development team will continue to pursue new opportunities for power generation projects in both Canada and the United States. Utility Services is expecting limited organic growth due to the slowdown in the U.S. housing market. Utility Services has initiated rate cases at a number of its utilities and will initiate additional rate cases in 2009. These rate cases are discussed in further detail within this MD&A (see UTILITY SERVICES: Outlook). While a firm forecast of rate increases at these facilities is not possible as the rate case processes are in progress, the resolution of rate cases is expected to potentially result in increased annual EBITDA at Utility Services of more than $10 million. The regulatory review of the rates and tariffs for these facilities are expected to conclude in the second half of 2009, with the new rates and tariffs going into effect between mid 2009 and the first half of 2010, depending on the state in which the facility operates. The business unit will also continue to consider accretive water and waste-water utility acquisition opportunities, as well as acquisitions in other regulated utilities, such as natural gas distribution and electricity distribution.

In all of its business units, Algonquin is committed to the growth and development of Algonquin's team through various training programs, challenging assignments and learning opportunities. In addition, Algonquin ensures continuous environmental, health and safety training for its operations and maintenance staff. The Company will continue to invest in information technology to reduce operating and administrative costs.

Overall, Algonquin's business units will focus on priorities that enable Algonquin to be an innovative, respected and socially responsible participant in the renewable energy, power and utility businesses and to maximize value for the Company in the current state of the financial markets. With a mix of complementary regulated and non-regulated businesses, the Company strives to enhance unitholder value through stable cash flows, sustainable cash distributions and a managed risk profile.

## POWER GENERATION & DEVELOPMENT

### Renewable Energy Division

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2008** | 2007 | **2008** | 2007 |
| **Performance (MW-hrs sold)** | | | | |
| Quebec Region | **78,720** | 70,353 | **320,025** | 275,863 |
| Ontario Region | **33,072** | 22,578 | **147,125** | 113,917 |
| Manitoba Region | **105,643** | 93,612 | **377,450** | 354,986 |
| New England Region * | **21,066** | 10,248 | **84,950** | 52,607 |
| New York Region | **25,461** | 17,715 | **92,000** | 72,841 |
| Western Region | **12,790** | 8,193 | **69,050** | 67,685 |
| **Total** | **276,752** | 222,699 | **1,090,600** | 937,899 |
| **Revenue** | | | | |
| Energy sales * | **$ 19,175** | $ 15,064 | **$ 75,549** | $ 49,688 |
| Other revenue | **-** | 1,666 | **-** | 17,123 |
| **Total revenue** | **$ 19,175** | $ 16,730 | **$ 75,549** | $ 66,811 |
| **Expenses** | | | | |
| Operating expenses * | **(6,160)** | (4,989) | **(22,015)** | (16,132) |
| Other income | **507** | 442 | **1,477** | 2,571 |
| Realized Gain (Loss) on derivative financial instruments | **(140)** | 83 | **(448)** | 67 |
| Division operating profit (including other income) | **$ 13,382** | $ 12,266 | **$ 54,563** | $ 53,317 |

* Prior period comparative amounts have been adjusted due to the classification of certain New England hydroelectric facilities as Discontinued Operations.

## 2008 Annual Operating Results

For the year ended December 31, 2008 the Renewable Energy division produced 1,090,600 MW-hrs of electricity, as compared to 937,899 MW-hrs produced in the same period in 2007, an increase of 16.3%. This level of production represents sufficient renewable energy to supply the equivalent of 60,600 homes with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 600,000 tons of CO2 gas was prevented from entering the atmosphere in 2008.

As Algonquin's facilities in the New England region are primarily subject to market rates, the average revenue earned per MW-hr sold can vary significantly from the same period in the prior year. Algonquin's facilities in the other regions are subject to varying rates, by facility, as set out in the facility's individual power purchase agreement ("PPA"). As such, while most of Algonquin'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.

For the year ended December 31, 2008, revenue from energy sales in the Renewable Energy division totalled $75.5 million, as compared to $49.7 million during the same period in 2007. During the year ended December 31, 2008, the division generated electricity equal to 106.5% of long term projected average resources (wind and hydrology) as compared to 92.6% during the same period in 2007. In 2008, a number of regions experienced resources at significantly higher levels than long term average, including the Quebec region which was 13.9% above long term averages and the New England region, which was 38.1% above long term averages. All other regions, with the exception of Ontario, experienced above long term average resources in the year ended December 31, 2008. During the same period in 2007, only the Western region experienced above long term average resources.

The increase in revenue from energy sales in the year ended December 31, 2008, as compared to the same period in 2007, was primarily the result of an increase of $15.2 million due to the St. Leon facility achieving commercial operation on September 18, 2007, when liquidated damages (recorded as 'Other Revenue') ceased and energy sales commenced to be earned by the facility. For comparison purposes, energy production data at St. Leon, during the time when the facility earned liquidated damages, has been included in the Manitoba regional 'Performance' numbers in 2007. Weighted average energy rates earned by Algonquin's U.S. facilities increased $1.3 million or 13% primarily due to increased market rates earned in the New England region, as compared to the same period in 2007. Revenue increased $3.0 million in the U.S. regions and $5.8 million in the Quebec, Ontario and Western regions, resulting from higher energy production as compared to the same period in 2007. In the comparable period, revenue from the St. Leon facility primarily consisted of liquidated damages and was recorded as Other Revenue. Weighted average energy rates earned by Algonquin's Canadian facilities decreased $0.3 million or 1% primarily due to changes in the weighted average production at facilities earning lower energy rates, as compared to the same period in 2007. The division reported increased revenue of $0.2 million from U.S. operations as a result of the weaker Canadian dollar.

For the year ended December 31, 2008, operating expenses totalled $22.0 million, as compared to $16.1 million during the same period in 2007, an increase of $5.9 million. Operating expenses were impacted by increased operating costs of $0.5 million and increased variable costs tied to production, totalling $1.1 million. Additional cost increases were due to an increase of $0.4 million in repairs and maintenance projects initiated in the period, costs of $2.1 million associated with the pursuit of various growth and development activities, and increased operating costs of $0.5 million at the St. Leon facility due to the achievement of commercial operation, as compared to the same period in 2007. The expenses in the comparative period include a non-recurring recovery of operating expenses at the St. Leon facility.

During the year ended December 31, 2008, Algonquin earned lower interest and other income related to its renewable energy investments as compared to the same period in 2007. In addition, the comparable period included the recognition of interest income earned on unpaid liquidated damages at the St. Leon facility up to September 2007, the commercial operation date of the facility.

The realized portion of gain on financial instruments consists of any actual gains on foreign exchange forward contracts and interest rate swaps settled in the quarter. Unrealized mark to market gains or losses on derivative financial instruments are not considered in management's evaluation of divisional performance, and therefore are reported in the Corporate segment.

For the year ended December 31, 2008, operating profit totalled $54.6 million, as compared to $53.3 million during the same period of 2007, representing an increase of 2.3%. For the year ended December 31, 2008, operating profit exceeded Algonquin's expectations primarily due to greater than long term average resource availability.

## 2008 Fourth Quarter Operating Results

In the quarter ended December 31, 2008, the Renewable Energy division produced 276,752 MW-hrs of electricity, as compared to 222,699 MW-hrs produced in the same period in 2007, an increase of 24.3%. This level of production in the fourth quarter of 2008 represents sufficient renewable energy to supply the equivalent of 61,500 homes with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 152,000 tons of CO2 gas was prevented from entering the atmosphere in the fourth quarter of 2008.

As Algonquin's facilities in the New England region are primarily subject to market rates, the average revenue earned per MW-hr sold can vary significantly from the same period in the prior year. Algonquin's facilities in the other regions are subject to varying rates, by facility, as set out in the facility's individual PPA. As such, while most of Algonquin'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.

For the quarter ended December 31, 2008, revenue from energy sales in the Renewable Energy division totalled $19.2 million, as compared to $15.1 million during the same period in 2007, an increase of $4.1 million. During the fourth quarter of 2008, the division generated electricity equal to 105.1% of long term projected average resources (wind and hydrology), as compared to 85.0% during the same period in 2007. In the fourth quarter of 2008, a number of regions experienced resources at significantly higher levels than long term average including the Quebec region which was 7.3% above long term averages, the New England region which was 45.2% above long term averages, and the New York region which was 9.9% above long term averages. All other regions with the exception of Ontario and Western experienced above long term average resources in the fourth quarter of 2008. During the same period in 2007, all regions experienced below long term average resources.

The increase in revenue from energy sales as compared to the fourth quarter of 2007 was partially the result of an increase of $1.0 million due to the St. Leon facility achieving commercial operation on September 18, 2007, when liquidated damages (recorded as 'Other Revenue') ceased and energy sales commenced to be earned by the facility. For comparison purposes, energy production data at St. Leon, during the time when the facility earned liquidated damages, has been included in the Manitoba regional 'Performance' numbers of the prior year. Revenue increased $1.7 million in the U.S. regions resulting from higher energy production and $1.3 million in the Quebec, Ontario and Western regions resulting from higher energy production and weighted average energy rates. Three Quebec facilities generated energy in excess of 120% of long term averages during the PPA contract year ended November 2008 and thus earned a lower incremental rate on energy in the quarter. This resulted in a reduction of revenue of $0.2 million earned in November 2008 due to lower energy rates. Increased revenue from higher energy production was partially offset by $0.6 million resulting from a 22% decrease in weighted average energy rates earned by Algonquin's U.S. facilities, primarily in the New England region, as compared to the same period in 2007. Weighted average energy rates earned by Algonquin's Canadian facilities remained consistent with the same period in 2007 due to changes in the weighted average production at facilities earning lower energy rates. In the comparable period, a portion of revenue from the St. Leon facility consisted of liquidated damages and was recorded as Other Revenue. The division reported increased revenue of $0.5 million from U.S. operations as a result of the weaker Canadian dollar.

Other Revenue in 2007 consisted of liquidated damages earned by the St. Leon facility in the amount of $17.1 million all of which occurred in the first three quarters of the year ended December 31, 2007. As a result of the St. Leon facility achieving Commercial Operation in September 2007, no liquidated damages were earned in fourth quarter of 2007 or 2008.

For the quarter ended December 31, 2008, operating expenses totalled $6.2 million as compared to $5.0 million during the same period in 2007, an increase of $1.2 million. Operating expenses were impacted by increased operating costs of $0.1 million and increased variable costs tied to production totalling $0.2 million. Additional cost increases were due to costs of $0.2 million as a result of achieving commercial operation at the St. Leon facility and costs of $0.9 million associated with various growth and development activities as compared to the same period in 2007. The expenses in the comparative period include a non-recurring recovery of operating expenses at the St. Leon facility.

For the quarter ended December 31, 2008, the Renewable Energy division's operating profit totalled $13.4 million, as compared to $12.3 million during the same period of 2007, representing an increase of 9.1%. For the quarter ended December 31, 2008, operating profit exceeded Algonquin's expectations primarily due to greater than long term average resource availability.

## Divisional Outlook – Renewable Energy

The Renewable Energy division is expected to perform at or above long term average resource conditions in the first quarter of 2009. In addition, the facilities in the New York and New England region are expected to experience reduced market rates as compared to the rates experienced in 2008.

As a result of certain legislation passed in Quebec (Bill C93), Algonquin'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. Algonquin anticipates incurring costs of $0.1 million during 2009 to complete the required assessments. Upon completion of these assessments, Algonquin 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, Algonquin has initially identified capital expenditures estimated at approximately $14.5 million. Algonquin anticipates that these expenditures will be required to be invested over the next five years as follows:

| | Total | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| Estimated Bill C-93 Capital Expenditures | **14,500** | 3,100 | 4,500 | 1,600 | 2,800 | 2,500 |

The majority of these capital costs are associated with the Donnaconna, St. Alban and Mont-Laurier facilities. Algonquin does not anticipate any significant impact on power generation or associated revenue while the dam safety work is ongoing. Algonquin 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.

## POWER GENERATION & DEVELOPMENT:

### Thermal Energy Division

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2008** | **2007** | **2008** | **2007** |
| **Performance** (MW-hrs sold) * | **145,050** | 131,032 | **597,923** | 570,853 |
| **Performance** (tonnes of waste processed) | **42,348** | 40,088 | **161,198** | 140,618 |
| **Revenue** | | | | |
| Energy sales * | **$ 21,806** | $ 14,329 | **$ 82,959** | $ 66,877 |
| Less: | | | | |
| Cost of Sales – Fuel ** | **(11,597)** | (7,797) | **(44,706)** | (37,901) |
| Net Energy Sales Revenue | **$ 10,209** | $ 6,532 | **$ 38,253** | $ 28,976 |
| Waste disposal sales | **3,998** | 3,923 | **15,706** | 13,609 |
| Other revenue | **1,691** | 1,345 | **4,349** | 5,179 |
| Total net revenue | **$ 15,898** | **$ 11,800** | **$ 58,308** | **$ 47,764** |
| **Expenses** | | | | |
| Operating expenses * | **(8,807)** | (6,926) | **(32,515)** | (27,880) |
| Interest and other income | **868** | 969 | **3,665** | 4,878 |
| Realized gain on derivative financial instruments | **(221)** | 2,509 | **1,595** | 6,244 |
| **Division operating profit** (including interest and dividend income) | **$ 7,738** | **$ 8,352** | **$ 31,053** | **$ 31,006** |

* Prior period comparative amounts have been adjusted due to the classification of certain landfill gas ("LFG") facilities as Discontinued Operations.

** 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.

### 2008 Annual Operating Results

For the year ended 2008, EFW processed 161,198 tonnes of waste, as compared to 140,618 tonnes of waste processed in the previous year, an increase of 14.6%. This level of production resulted in the diversion of approximately 112,350 tonnes of waste from landfill sites in the year ended 2008.

For the year ended December 31, 2008, revenue in the Thermal Energy division totalled $103.0 million, as compared to $85.7 million during the same period in 2007, an increase of $17.3 million. During the year ended December 31, 2008, the business unit's performance increased by 31,200 MW-hrs at the Sanger Facility as a result of the re-powering and by 12,400 MW-hrs due to increased production at the LFG facilities, partially offset by lower demand of 2,000 MW-hrs at the Windsor Locks facility and lower energy production of 15,000 MW-hrs at the EFW facility as a result of the business unit's BCI steam sales facility reaching commercial operation in June 2008 and a portion of the steam generated by the incineration processes at the EFW facility is now being utilized by BCI for steam sales rather than being used to generate electricity, as compared to the same period in 2007. The EFW facility increased throughput by over 20,500 tonnes, as compared to the same period in 2007 for the reasons discussed above. Throughput at EFW in the prior period was negatively impacted by a 14 day planned major outage and unplanned repairs to the evaporative cooling towers.

For the year ended December 31, 2008, energy sales revenue at the Thermal Energy division totalled $83.0 million, as compared to $66.9 million during the same period in 2007, an increase of $16.1 million. The increase in revenue from energy sales as compared to the comparable period in 2007 was primarily due to increases of $5.1 million as a result of increased production at the Sanger facility, $3.8 million as a result of the BCI steam sales facility achieving commercial operation in June 2008, $1.4 million as a result of increased production and higher energy rates at the LFG facilities, and $6.8 million resulting from increased energy rates at the Windsor Locks facility. The Windsor Locks facility experienced higher energy rates while the Sanger facility experienced lower energy rates as changes in the rate charged for natural gas used at the facilities are passed on to the customer in the energy price. This was partially offset by decreased revenue of $0.2 million as a result of decreased production at the Windsor Locks facility, $0.4 million as a result of lower energy rates at the Sanger facility and $0.9 million at the EFW facility for the reasons discussed above.

Revenue from waste disposal sales for the year ended December 31, 2008 totalled $15.7 million as compared to $13.6 million during the same period in 2007, an increase of $2.1 million. The increase was due to increased throughput and improved pricing for ash handling at the EFW facility, as compared to the same period in 2007.

For the year ended December 31, 2008, fuel costs at Sanger and Windsor Locks totalled $44.7 million, as compared to $37.9 million during the same period in 2007, an increase of $6.8 million. Natural gas expense makes up approximately 75% of operating expenses at the Sanger facility. Natural gas expense at Sanger increased by $1.9 million, or 26%, the result of a 24% increase in the price for natural gas combined with a 32% increase in production. During the prior period, the Sanger facility experienced lower production resulting from a planned shut-down due to the repowering project. Natural gas expense makes up approximately 90% of operating expenses at the Windsor Locks facility. Natural gas expense at the Windsor Locks facility increased by $4.9 million, or 18%, the result of an 18% increase in the price for natural gas as compared to the same period in 2007.

For the year ended December 31, 2008, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $32.5 million as compared to $27.9 million during the same period in 2007, an increase of $4.6 million. The increase in operating expenses for the year was primarily due to $2.0 million as a result of the operating costs of the BCI steam sales facility, $0.6 million at the Sanger facility resulting from increased operating costs, $0.2 million at the EFW facility primarily resulting from increased operating costs and natural gas expense, $1.0 million at the LFG facility primarily resulting from increased operating and repair and maintenance expenses, $0.2 million associated with the pursuit of various growth opportunities and $0.4 million at the Valley Power facility primarily resulting from increased operating and repair and maintenance expenses in 2008 as compared to 2007. Natural gas expense makes up approximately $1.4 million or 70% of operating expenses at the BCI facility. 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 lower operating expenses of $1 million from U.S. operations as a result of the weaker Canadian dollar.

During the year ended December 31, 2008, Algonquin earned lower interest and other income on its portfolio investments, as compared to the same period in 2007 due to lower earnings of $0.3 million from its investments in two co-generation facilities, as compared to the same period in 2007. In addition, the comparable period included $0.9 million related to the landfill gas investments and the production tax credit program which did not extend past December 31, 2007.

The realized portion of gain on financial instruments consists of any actual gains on the foreign exchange forward contracts and interest rate swaps settled in the year. Unrealized mark to market gains or losses on derivative financial instruments are not considered in management's evaluation of divisional performance and therefore are reported in the Corporate segment.

For the year ended December 31, 2008, operating profit totalled $31.1 million, as compared to $31.0 million during the same period in 2007. The Thermal Energy division has shown improved operating performance during the year ended December 31, 2008, as compared to the same period in 2007, achieving a number of performance targets established for the division. However, operating profit did not fully meet the Company's expectations for the twelve months ended December 31, 2008 primarily due to increased operating and other expenses related to the Division's LFG assets.

## 2008 Fourth Quarter Operating Results

In the fourth quarter of 2008, the Thermal Energy division's EFW facility processed 42,348 tonnes of municipal solid waste as compared to 40,088 tonnes processed in the same period of 2007, an increase of 5.6%. This level of production resulted in the diversion of approximately 29,800 tonnes of waste from landfill sites in the fourth quarter of 2008.

For the quarter ended December 31, 2008, revenue in the Thermal Energy division totalled $27.5 million, as compared to $19.6 million during the same period in 2007, an increase of $7.9 million. During the quarter ended December 31, 2008, the business unit's BCI steam sales facility was operating for the full quarter having reached commercial operation in June 2008. As a result, a portion of the steam generated by the incineration processes at the EFW facility is now being utilized by BCI for steam sales rather than being used to generate electricity. Although this has resulted in the decrease in electrical generation from EFW's steam turbine of 8,900 MW-hrs, it is being more than offset from the new steam sales by BCI. In addition, the decrease in electrical generation was partially offset by increases of 16,200 MW-hrs at the Sanger facility as a result of the re-powering project and 3,300 MW-hrs due to increased production at the LFG facilities, as compared to the same period in 2007. Throughput at the EFW facility improved from the previous quarter of 2008 and from the same period in 2007, in part due to new enhanced design boiler tube installation completed in the second quarter of 2008.

For the quarter ended December 31, 2008, energy sales revenue at the Thermal Energy division totalled $21.8 million, as compared to $14.3 million during the same period in 2007, an increase of $7.5 million. The increase in revenue from energy sales, as compared to the fourth quarter of 2007, was primarily due to an increase of $3.2 million as a result of increased production at the Sanger facility, $1.4 million as a result of increased energy rates and production at the Windsor Locks facility, $0.7 million as a result of increased production at the LFG facilities, and $1.7 million as a result of the BCI steam sales facility achieving commercial operation in June 2008. These increases were offset by a decrease of $2.2 million as a result of lower energy rates at the Sanger facility due to lower natural gas prices, $0.8 million as a result of lower energy rates at the LFG facilities, and $0.5 million as a result of a portion of the steam generated by the incineration processes at the EFW facility being used by BCI instead of being used to generate electricity. The division reported increased revenue of $3.8 million from operations as a result of the weaker Canadian dollar, as compared to the same period of 2007.

Revenue from waste disposal sales for the quarter ended December 31, 2008 totalled $4.0 million, as compared to $3.9 million during the same period in 2007, an increase of $0.1 million. The increase was due to increased throughput at the EFW facility, as compared to the same period in 2007.

For the quarter ended December 31, 2008, fuel costs at Sanger and Windsor Locks totalled $11.6 million, as compared to $7.8 million during the same period in 2007, an increase of $3.8 million. Natural gas expense makes up approximately 65% of operating expenses at the Sanger facility. Natural gas expense at Sanger increased by $0.6 million, or 60%, primarily as a result of a 112% increase in production, increasing the volume of natural gas used in ongoing operation of the facility. This increase was partially offset by an 11% decrease in the price for natural gas as compared to the same period in 2007. During the prior period, the Sanger facility experienced lower production resulting from a planned shut-down due to the repowering project. Natural gas expense makes up approximately 90% of operating expenses at the Windsor Locks facility. Natural gas expense at the Windsor Locks facility increased by $1.0 million, or 15%. This was primarily as a result of a 14% increase in the price for natural gas, as compared to the same period in 2007. The division reported increased fuel costs of $2.2 million as a result of the weaker Canadian dollar.

For the quarter ended December 31, 2008, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $8.8 million, as compared to $6.9 million during the same period in 2007, an increase of $1.9 million. The increase in operating expenses for the quarter was primarily due to $0.9 million as a result of the operating costs of the BCI steam sales project, $0.2 million due to increased operating costs at the LFG facilities, and $0.2 million due to increased operating costs at the Sanger facility as compared to the same period in 2007. These increases were partially offset by decreased operating expenses of $0.4 million at the EFW facility. Natural gas expense makes up approximately $0.6 million or 70% of operating expenses at the BCI facility. 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.

For the quarter ended December 31, 2008, the Thermal Energy division's operating profit totalled $7.7 million, as compared to $8.4 million during the same period in 2007, representing a decrease of 8.3 %. Operating profit in the Thermal Energy division met the Company's expectations for the three months ended December 31, 2008, due to strong performances from the Division's co-generation assets.

## Divisional Outlook – Thermal Energy

The Thermal Energy division's EFW facility is expected to operate in line with Algonquin's expectations during 2009. Operations at the EFW facility have improved during the last year due in part to a new enhanced design for boiler tubes being installed and this improved performance is expected to continue through 2009.

The Thermal Energy division's Windsor Locks and Sanger facilities are expected to continue to operate through 2009 in line with Algonquin's long term expectations. The Windsor Locks facility has a planned hot gas path inspection occurring in Q2 2009 lasting approximately 8 – 10 days which will result in an expected reduction in operating profit of $0.3 million, as compared to its otherwise expected operating profit.

As a result of the re-powering of the Sanger facility, 14MW of additional production is available. An additional 6 MW can be exported with the existing 69 kV substation while an upgrade of the existing line voltage by Pacific Gas and Electric Company ("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 will install a new substation with additional investment of approximately U.S. $2.0 million. PG&E's upgrade is anticipated 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 2009.

## POWER GENERATION & DEVELOPMENT:

## Development Division

The Development division works to identify, develop and construct new renewable and high efficiency thermal energy generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of Algonquin's existing facilities. Development is focused on projects in North America with a commitment to working proactively with all stakeholders, including local communities. The Development division is lead by five dedicated full time employees based out of the Company's head office. In addition, the division has access to and support from all of the available resources and experience throughout the Company to assist it in the development of projects, including finance, engineering and technical services, as well as regulatory compliance. The division also utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, including those in the financial, legal, engineering, technical, and construction sectors.

The Development division may also create opportunities through the acquisition of prospective projects that are at various stages of development. The turbulence in the economic environment is also opening up opportunities for Algonquin to acquire third party development projects experiencing financial difficulty or source capital equipment from financially distressed third party projects at discounted prices, which can serve to increase expected returns for Algonquin's development efforts. The business 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.

Once a project has reached commercial operation status, the facility will either be transferred to and operated directly by the Renewable Energy or the Thermal Energy division or sold to third party operators.

## Current Development Projects

Following up on the repowering of the Sanger facility in late 2007 and the commissioning of the BCI facility in 2008, the Development division has focussed resources on identifying new development projects internally and externally, as well as pursuing the development opportunities already identified as having potential to be in line with Algonquin's investment criteria.

Algonquin continues to develop the 25 MW Red Lily Wind Project (the "Project") in south-eastern Saskatchewan through a joint development agreement with an unrelated third party corporation. In July 2008, a PPA for the facility was executed with SaskPower after the Project was successfully bid into a SaskPower Environmentally Preferred Power Strategy Request for Proposal. In October 2008, the Project submitted a Notice of Project Application with Natural Resources Canada under the ecoENERGY for Renewable Power Program, and, in December 2008, the Project received a registration number under the program, confirming its eligibility for the federal incentive program. In follow-up, in December 2008, the Project submitted its stage two documentation, the Technical Information Package, which is under review by Natural Resources Canada. As well, in December 2008, as expected, the Project submitted the Environmental Impact Assessment to Saskatchewan Environment for review. The Provincial review is expected to be completed in Q1 2009.

Successful development of wind projects such as Red Lily are subject to significant risks and uncertainties including ability to obtain financing on acceptable terms, currency fluctuations affecting the cost of major capital components such as wind turbines, price escalation for construction labour and other construction inputs, construction risk that the project is built without mechanical defects, and is completed on time and within budget estimates. In the event the Project is developed, it is currently estimated to require 16 turbines with a capital investment of approximately $60 - 65 million. Annual energy production from the wind farm is estimated to be 92,000 MW-hrs and annual gross revenue is estimated to be $8.9 million. The current estimate of the earliest time the project could be completed is March 31, 2011.

Algonquin is also pursuing the re-development of the Windsor Locks facility in Connecticut. As the PPA with Connecticut Light & Power reaches maturity in 2010, a variety of options for alternative sales of energy or re-powering of the facility's prime power plant with equipment to match the current steam demand of the paper mill host are being considered. The energy services agreement with the paper mill will, if not further extended by mutual agreement, continue until 2017.

Algonquin has completed preliminary engineering and a financial feasibility analysis on a 10 MW to 19 MW combined cycle high efficiency thermal energy generation project located in Ontario. Additional, information will be provided in the event that this project evolves.

## 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, including six wind projects in Canada 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.

During the year Algonquin invested $0.5 million to acquire 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 would be constructed after environmental approvals are granted, a process that has been initiated and is currently estimated to require 2 to 3 years to complete.

In 2008, Algonquin made a strategic decision to maintain land option agreements for two wind projects in Quebec in anticipation of future provincial tenders expected in the first quarter of 2009 for wind projects of a 25 MW maximum size. In addition, Algonquin has maintained a relationship with a development co-op comprised of landowners and other small investors for the potential development of a third project in response to the expected call for tender.

Discussions with the Ontario Power Authority indicate that energy procurement initiatives will be positively influenced by the Green Energy Act introduced by the McGuinty government through Bill 150 on February 23, 2009. The Green Energy Act 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, 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 Green Energy Act. In addition, Algonquin Power has applied to become applicant of record for three crown land sites under Ministry of Natural Resources wind power site release program.

Each project being contemplated is subject to a significant level of due diligence and financial modeling to ensure it satisfies return and diversification objectives established for the Development division. Accordingly, the likelihood of proceeding with some or all of these projects depends on the outcome of due diligence, material contract negotiations, the structure of future calls for tender, and request for proposal programs. To maximize Algonquin'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. Algonquin 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 the Power Generation & Development business unit 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 internal steam load at a nearby recycled paper board manufacturing mill. Algonquin 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. Algonquin is currently evaluating the feasibility of an expanded facility including associated capital and operating costs and financing terms. Algonquin 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.

As a result of the re-powering of the Sanger facility, 14MW of additional production is available, in excess of what is currently being sold under the existing PPA under which the facility operates. The Development division is currently reviewing the options to market this increased capacity at the Sanger Facility. See Divisional Outlook – Thermal Energy section for more details on the sale of this additional power.

## Divisional Outlook - Development

Algonquin 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. Most recently the Ontario government announced plans to introduce the Green Energy Act. As announced, this legislation will require the responsible power purchase authority to grant priority and obligatory purchase of green energy projects, an obligation for all utilities to grant priority grid access to green energy projects, and a system of tariffs as the primary procurement mechanism for renewable and clean energy. 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, 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 1,856 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; Quebec -4,500 MW by 2016, Alberta - 2,500 MW in additional transmission options, Manitoba - 1,000 by 2017 and an additional 800 MW by 2015 in the Maritime Provinces and 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.

Algonquin will continue to actively pursue development projects which provide the opportunity to exhibit accretive growth. Algonquin 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. 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 benefit from the desire by various government entities to increase infrastructure spending.

## UTILITY SERVICES

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2008** | **2007** | **2008** | **2007** |
| **Number of** | | | | |
| Waste-water customers | **32,893** | 32,582 | **32,893** | 32,582 |
| Waste-water treated (millions of gallons) | **450** | 500 | **1,850** | 1,950 |
| Water distribution customers | **36,297** | 35,755 | **36,297** | 35,755 |
| Water sold (millions of gallons) | **1,400** | 1,400 | **5,750** | 5,650 |
| **Revenue** | | | | |
| Waste-water treatment | **$ 5,279** | 4,270 | **$ 18,745** | 17,455 |
| Water distribution | **4,336** | 3,464 | **15,609** | 15,232 |
| Other Revenue | **221** | 257 | **879** | 1,012 |
| | **$ 9,836** | $ 7,991 | **$ 35,233** | $ 33,699 |
| **Expenses** | | | | |
| Operating expenses | **(6,041)** | (4,210) | **(21,243)** | (17,401) |
| Other income | **55** | - | **102** | 33 |
| Realized gain on derivative financial instruments | **(124)** | 1,134 | **3,482** | 3,296 |
| Business Unit operating profit (including other income) | **$ 3,726** | $ 4,915 | **$ 17,574** | $ 19,627 |

## 2008 Annual Operating Results

Utility Services had 32,893 waste-water customers as at December 31, 2008, as compared to 32,582 as at December 31, 2007, an increase of 311 customers year over year or 1.0%. The business unit's water distribution customers were 36,297 as at December 31, 2008, as compared to 35,755 as at December 31, 2007, representing a year over year increase of 542 customers or 1.5%.

During the year ended December 31, 2008, Utility Services provided approximately 5.8 billion U.S. gallons of water to its customers, treated approximately 1.9 billion U.S. gallons of waste-water, and sold approximately 530 million U.S. gallons of effluent.

For the year ended December 31, 2008, Utility Services' revenue totalled $35.2 million, as compared to $33.7 million during the same period in 2007. Revenue from waste-water treatment totalled $18.7 million, as compared to $17.5 million during the same period in 2007, an increase of $1.2 million. Revenue from water distribution totalled $15.6 million, as compared to $15.2 million during the same period in 2007, an increase of $0.4 million. Waste-water treatment revenue for the year ended December 31, 2008 was impacted by increased revenue at ten facilities, totaling $1.1 million. The increase was primarily the result of increased rates at the Gold Canyon facility, organic growth and increased customer demand at the Litchfield Park Service Company ("LPSCo") waste-water treatment facility. Water distribution revenue for the year ended December 31, 2008 was impacted by increased revenue at eight facilities, totaling $0.4 million. The increase was primarily the result of increased customer demand at the LPSCo's water distribution facility. The increase was partially offset by decreased water distribution revenue of $0.1 million at five water distribution facilities during the year as compared to the same period in 2007.

For the year ended December 31, 2008, operating expenses totalled $21.2 million, as compared to $17.4 million during the same period in 2007. Operating expenses increased by $1.8 million as a result of additional field personnel, contract and other operational expenses, $0.6 million as a result of increased power and chemical expenses, and $1.0 million as a result of increased billing and administrative expenses, as compared to the same period in 2007. The rate cases initiated by Utility Services will factor these increased operating expenses into the new rates and tariffs that the facilities are allowed to charge after the rate cases are complete. See Utility Services - Outlook section for more details on the rate cases initiated.

The realized portion of gain on derivative financial instruments consists of any realized gains on the foreign exchange forward contracts and interest rate swaps settled in the period.

For the year ended December 31, 2008, operating profit totalled $17.6 million as compared to $19.6 million during the same period in 2007 representing a decrease of 10.5%. Utility Services' operating profit did not meet the Company's expectations for the twelve months ended December 31, 2008 due to slower organic growth and higher operating costs experienced in the period.

## 2008 Fourth Quarter Operating Results

Utility Services had 32,893 waste-water customers as at December 31, 2008, as compared to 32,704 as at September 30, 2008, an increase of 190 in the quarter or 0.6%. Utility Services had 36,297 water distribution customers as at December 31, 2008, as compared to 36,108 as at September 30, 2008, an increase of 189 in the quarter or 0.5%. Utility Services' marginal increase in water distribution and waste-water treatment customer base during the quarter primarily relates to limited organic growth at the division's facilities, partially offset by an increase in vacant houses and the slow down in U.S. new residential home sales, primarily in the area serviced by LPSCo.

During the quarter ended December 31, 2008, Utility Services provided approximately 1.4 billion U.S. gallons of water to its customers, treated approximately 450 million U.S. gallons of waste-water, and sold approximately 130 million U.S. gallons of effluent.

For the quarter ended December 31, 2008, Utility Services' revenue totalled $9.8 million as compared to $8.0 million during the same period in 2007. Revenue from waste-water treatment totalled $5.3 million, as compared to $4.3 million during the same period in 2007, an increase of $1.0 million. Revenue from water distribution totalled $4.3 million, as compared to $3.5 million during the same period in 2007, an increase of $0.8 million. The fourth quarter water distribution revenue was impacted by increased revenue of $0.1 million resulting from organic growth and increased customer demand at six water distribution facilities. The fourth quarter waste-water treatment revenue was impacted by lower revenue of $0.1 million, due to decreased customer demand at six waste-water treatment facilities as compared to the same period in 2007. Utility Services reported increased revenue from operations of $1.9 million in the fourth quarter of 2008 as a result of the weaker Canadian dollar as compared to the same period in 2007.

For the quarter ended December 31, 2008, operating expenses totalled $6.0 million, as compared to $4.2 million during the same period in 2007. Operating expenses increased by $0.2 million as a result of additional field personnel, contract and other operational expenses, $0.2 million as a result of increased power and chemical expenses, and $0.4 million as a result of increased billing and administrative expenses, as compared to the same period in 2007. These increases were partially offset by $0.2 million of decreased property taxes expensed in the quarter ended December 31, 2008, as compared to the same period in 2007. Utility Services reported higher expenses from operations of $1.1 million as a result of the weaker Canadian dollar, as compared to the same period in 2007.

The realized portion of gain on derivative financial instruments consists of any realized gains on the foreign exchange forward contracts and interest rate swaps settled in the period.

For the quarter ended December 31, 2008, operating profit totalled $3.7 million as compared to $4.9 million during the same period in 2007, representing a decrease of 24.5%. Utility Services' operating profit did not meet the Company's expectations for the three months ended December 31, 2008 due to slower organic growth and higher operating costs experienced in the period.

## Outlook – Utility Services

Utility Services is not expecting any material organic growth in fiscal 2009 due to the slowdown in the U.S. housing market. However, Utility Services continues to provide water distribution and waste-water treatment services, primarily in the southern and southwestern United States, focusing on attractive historically-growing communities which provide opportunity for organic growth over the long term.

Utility Services is preparing to initiate rate cases at a number of its facilities. Black Mountain Sewer Company filed a rate case in December 2008 using a June 2008 test year. LPSCo will file a rate case in the first quarter of 2009, using a September 2008 test year. The Rio Rico facility is preparing to initiate a rate case during the first quarter or early second quarter of 2009, using a test year ended December 31, 2008. The Bella Vista, Northern Sunrise and Southern Sunrise facilities are preparing to initiate rate cases in 2009. All of these facilities are located in Arizona. Five Texas utilities are preparing to initiate rate cases in early 2009, with a test year ended December 31, 2008. The following table summarizes the larger rate cases that are being initiated:

| | Test Year | Status of Rate Increase | Estimated Revenue Increase as Filed | Estimated Timing of Rate Increase |
|---|---|---|---|---|
| **Facility** | | | | |
| Black Mountain | **Q2 2008** | Filed | $ 0.9 million | **Q1 2010** |
| LPSCo | **Q3 2008** | Filed | $ 12.5 million | **Q3 2010** |
| Rio Rico | **Q4 2008** | In progress | | **Q3 2010** |
| Bella Vista | **Q1 2009** | In progress | | **Q3 2010** |
| Texas Utilities | **Q1 2009** | In progress | | **Q2 2009** |

It is anticipated that regulatory review of the rates and tariffs for the Arizona facilities would be completed in the second half of 2009, with the new rates and tariffs going into effect in the second and third quarters of 2010. Due to differences in the regulatory approach between Arizona and Texas, it is anticipated that changes in the rates and tariffs for the Texas facilities would be in effect in mid 2009. While a firm forecast of rate increases at these facilities is not possible as the rate case processes are in the early stages and are subject to regulatory approval, the resolution of the rate cases noted above, over the course of fiscal 2010, is expected to potentially result in an annualized increase in revenue of more than U.S. $10 million. Rate cases ensure that a particular facility appropriately recovers its operating costs and earns the rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. Algonquin 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 full regulatory approved rate of return on its investments.

As part of normal rate case review procedures, existing customers and other interested parties are allowed to become involved and comment on a rate case review, generally when there is a requested increase in existing water distribution and waste-water treatment rates. As a result of a request by the Residential Utility Consumer Office ("RUCO"), the Arizona Corporation Commission ("ACC") agreed to re-hear the Gold Canyon rate case, originally decided in June 2007, which granted Gold Canyon a U.S. $1.8 million annualized increase in its rates. The rehearing focussed on two aspects of the original decision: Capital Structure and Excess Plant Capacity. This rehearing process concluded in December 2008, resulting in a reduction in the approved rates for Gold Canyon. This is anticipated to reduce annual revenue by approximately U.S. $0.6 million versus the initial rates granted in June 2007. Algonquin believes that this decision is not consistent with current legislation, existing precedents and is substantially without merit. The rate case review procedures provide the waste-water treatment provider with a number of options, including filing an appeal of this decision to the Arizona State Court of Appeals. Gold Canyon intends to exercise its rights as provided in the ratemaking process in Arizona and challenge the results of the rehearing process. As this process in the early stages, Algonquin is not able to estimate the likelihood of this decision being reversed.

Various capital projects in several utilities have achieved substantial completion during 2008 or will achieve completion during the first quarter of 2009. All of these investments will be included in the rate case applications previously noted.

## CORPORATE

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2008** | **2007** | **2008** | **2007** |
| Corporate and other expenses: | | | | |
| Administrative expenses | **2,812** | 2,389 | **9,419** | 8,463 |
| Management costs | **224** | 991 | **893** | 1,637 |
| Loss / (Gain) on foreign exchange | **2,345** | (742) | **4,018** | (7,688) |
| Interest expense | **5,711** | 6,901 | **26,288** | 26,565 |
| Interest, dividend and other Income | **(945)** | (49) | **(1,763)** | (1,926) |
| Loss / (Gain) on derivative financial instruments | **30,781** | 3,522 | **42,826** | (4,862) |
| Income tax expense (recovery) | **(4,438)** | (5,615) | **308** | 15,108 |

## OVERVIEW

### 2008 Annual Corporate and Other Expenses

During the year ended December 31, 2008, administrative expenses totalled $9.4 million as compared to $8.5 million in the same period in 2007. The increase in the twelve months ended December 31, 2008 was due to added requirements to administer Algonquin, including additional staff, higher legal and regulatory costs and inflationary increases.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and do not impact current cash available for distribution. For purposes of evaluating divisional performance, the Company does not allocate the unrealized foreign exchange gains or losses to specific divisions as the change does not impact the Company's current cash position. For the year ended December 31, 2008 Algonquin reported a foreign exchange loss of $4.0 million as compared to a gain of $7.7 million during the same period in 2007. The 2008 fiscal year has experienced an increase in value of the U.S. dollar of 22% which resulted in unrealized losses on Algonquin's U.S. denominated debt. The 2007 fiscal year experienced a decline in the value of the U.S. dollar of 16%, which resulted in unrealized gains on Algonquin's U.S. denominated debt. At the end of the 2008 fiscal year, Algonquin had approximately $33.1 million in U.S. dollar denominated debt.

For the year ended December 31, 2008, interest expense totalled $26.3 million, as compared to $26.6 million in the same period in 2007. Decreased interest expense related to Algonquin's credit facility was a result of lower interest rates and fees charged on variable interest credit facilities partially offset by increased average levels of debt held by Algonquin during 2008, as compared to the prior year.

For the year ended December 31, 2008, other income totalled $1.7 million as compared to $1.9 million in the same period in 2007. Algonquin recognized gains during the year pursuant to the sale of its investment in a bio-mass facility and through the sale of land rights, wind studies and other assets related to the potential development of a Canadian wind farm. The comparative period includes a termination fee related to Algonquin's offer to purchase the outstanding units of CPIF.

Gain or loss on derivative financial instruments consists of unrealized mark to market gains or losses on foreign exchange forward contracts and interest rate swaps during the year. For purposes of evaluating divisional performance, the Company allocates the realized portion of the gain on financial instruments to specific divisions. The unrealized portion of any mark to market gains or losses on derivative instruments does not impact the Company's current cash position and are not considered in management's evaluation of divisional performance. Therefore, the unrealized portion of any mark to market gains or losses on derivative instruments is not allocated to specific divisions and is reported in the Corporate segment.

An income tax expense of $0.3 million was recorded in the year ended December 31, 2008, as compared to an expense of $15.1 million during the same period in 2007. The decrease in expense results in part from the recognition of unrealized mark to market losses on derivative instruments booked in the year and as a result of a significant number of capital projects completed during the year in the U.S., primarily at the LPSCo facility. These capital projects in the U.S. are entitled to record 'bonus depreciation' for tax purposes, resulting in an increased future tax expense recorded in the year ended December 31, 2008. In the comparative period, a non-recurring charge of $27.9 million was expensed relating to the substantive enactment of new Canadian tax regulations which were not reflected in the comparable period in 2007 (see Risk Management – Changes to income tax laws).

## 2008 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2008, administrative expenses totalled $2.8 million, as compared to $2.4 million in the same period in 2007. The expense increase in the three months ended December 31, 2008 was due to added requirements to administer Algonquin, including additional staff, higher legal and regulatory costs and inflationary increases.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and do not impact current cash available for distribution. For purposes of evaluating divisional performance, the Company does not allocate the unrealized foreign exchange gains or losses to specific divisions as the change does not impact the Company's current cash position. For the quarter ended December 31, 2008, Algonquin reported a foreign exchange loss of $2.3 million as compared to a gain of $0.7 million during the same period in 2007. An increase in value of the U.S. dollar of 16% in the quarter ended December 31, 2008 was experienced which resulted in unrealized losses on Algonquin's U.S. denominated debt. The fiscal year 2007 experienced a decline in the value of the U.S. dollar of 1% in the fourth quarter which resulted in unrealized gains on Algonquin's U.S. denominated debt. At the end of the fourth quarter of 2008, Algonquin had approximately $33.1 million in U.S. dollar denominated debt.

For the quarter ended December 31, 2008, interest expense totalled $5.7 million as compared to $6.9 million in the same period in 2007. Decreased interest expense related to Algonquin's credit facility was a result of lower interest rates and fees charged on variable interest credit facilities and increased interest capitalized on construction in Utilities Services, partially offset by increased average levels of debt held by Algonquin during the period, as compared to the prior year.

For the quarter ended December 31, 2008, other income totalled $0.9 million as compared to nil in the same period in 2007. Algonquin recognized a gain pursuant to the sale of its investment in a bio-mass facility.

Gain or loss on derivative financial instruments consists of unrealized mark to market gains or losses on foreign exchange forward contracts and interest rate swaps during the quarter. For purposes of evaluating divisional performance, the Company allocates the realized portion of the gain on financial instruments to specific divisions. The unrealized portion of any mark to market gains or losses on derivative instruments does not impact the Company's current cash position and are not considered in management's evaluation of divisional performance. Therefore, the unrealized portion of any mark to market gains or losses on derivative instruments is not allocated to specific divisions and is reported in the Corporate segment.

An income tax recovery of $4.4 million was recorded in the fourth quarter of 2008, as compared to a recovery of $5.6 million during the same period in 2007. The recovery resulted in part from the recognition of unrealized mark to market losses on derivative instruments booked in the quarter and as a result of a significant number of capital projects completed during the quarter in the U.S., primarily at the LPSCo facility. These capital projects in the U.S. are entitled to record 'bonus depreciation' for tax purposes, resulting in an increased future tax expense recorded in the three months ended December 31, 2008. (see Risk Management – Changes to income tax laws).

## Reconciliation of EBITDA to net earnings

The following tables are derived from and should be read in conjunction with the Consolidated Statement of Earnings. This supplementary disclosure is intended to more fully explain disclosures related to EBITDA and provides additional information related to the earnings of the Company. Investors are cautioned that these measures should not be construed as an alternative to GAAP consolidated statement of earnings.

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2008** | **2007** | **2008** | **2007** |
| Net earnings (loss) from continuing operations | **$ (21,095)** | $ 7,475 | **$ (19,038)** | $ 24,763 |
| Add: | | | | |
| Income tax provision (recovery) | **(4,438)** | (5,615) | **308** | 15,108 |
| Interest expense | **5,712** | 6,901 | **26,288** | 26,565 |
| (Gain) / loss on derivative financial instruments | **31,126** | (203) | **37,748** | (14,469) |
| (Gain) / loss on foreign exchange | **2,339** | (742) | **4,018** | (7,688) |
| Amortization | **11,536** | 9,774 | **43,846** | 41,565 |
| Other | **(1,924)** | 886 | **(3,142)** | 325 |
| EBITDA | **$ 23,256** | $ 18,476 | **$ 90,028** | $ 86,169 |

For the year ended December 31, 2008, EBITDA increased by $3.8 million. The increase in EBITDA is due to increased earnings from operations of $6.5 million resulting from high hydrological conditions experienced in the year, the commencement of commercial operations of the BCI steam sales project, and higher gas prices in the Thermal division, as compared to the previous year. These increases were partially offset by $2.4 million in lower interest dividend and other income earned in the year, as compared to the previous year. The 2008 figures include non-recurring gains of $1.6 million on the sale of certain assets, including Algonquin's interest in the Brooklyn facility and land rights related to the potential development of a wind farm, as compared to non-recurring gains in fiscal 2007 of $1.8 million, related to a termination fee resulting from an offer to purchase the outstanding units of CPIF, a reduction in operating expenses of $1.0 million related to the achievement of commercial operations at the St. Leon facility, and interest income earned on unpaid liquidated damages related to the St. Leon facility.

For the fourth quarter ending December 31, 2008, EBITDA increased by $4.8 million due to increased earnings from operations of $3.5 million, resulting from high hydrological conditions experienced in the quarter, the commencement of commercial operations of the BCI steam sales project, and higher gas prices and production in the Thermal division, as compared to the previous year. In addition, during the quarter ended December 31, 2008, Algonquin earned $0.9 million in increased interest dividend and other income, primarily related to non-recurring gains on the sale of Algonquin's interest in the Brooklyn facility.

## Cash Available for Distribution

The following tables are derived from and should be read in conjunction with the Consolidated Statement of Cash Flows. This supplementary disclosure is intended to more fully explain disclosures related to cash available for distribution and provides additional information related to the cash flows of the Company including the amount of cash available for distribution to unitholders. Investors are cautioned that these measures should not be construed as an alternative to GAAP consolidated statement of cash flows.

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2008** | **2007** | **2008** | **2007** |
| Cash provided by (used in) Continuing Operations [1] | **$ 13,866** | (705) | **$ 66,874** | 40,427 |
| Changes in working capital | **5,143** | 16,333 | **4,333** | 30,744 |
| | **19,009** | 15,628 | **71,207** | 71,171 |
| Receipt of principal on notes receivable | **1,009** | 236 | **1,241** | 1,319 |
| Repayment of long term liabilities | **(954)** | (467) | **(2,621)** | (1,305) |
| Maintenance capital expenditures [2] | **(890)** | (886) | **(3,997)** | (4,121) |
| Other – non-recurring [3] | **(137)** | 5,413 | **(771)** | 5,285 |
| Cash available for distribution | **$ 18,037** | $ 19,924 | **$ 65,059** | $ 72,349 |
| **Add Back:** | | | | |
| Maintenance expenditures | **890** | 886 | **3,997** | 4,121 |
| **Deduct:** | | | | |
| Net growth, maintenance and other expenditures | **(8,722)** | (12,586) | **(45,561)** | (39,571) |
| Cash available for distribution after growth and maintenance capital expenditures | **$ 10,205** | $ 8,224 | **$ 23,495** | $ 36,899 |
| Distribution to Unitholders | **$ 4,774** | $ 17,481 | **$ 57,755** | $ 69,923 |
| **Per Trust Unit** | | | | |
| Cash provided by (used in) Continuing Operations | **$ 0.17** | $ (0.01) | **$ 0.86** | $ 0.53 |
| Cash available for distribution | **$ 0.23** | $ 0.26 | **$ 0.84** | $ 0.95 |
| Cash available for distribution after net growth and maintenance expenditures | **$ 0.13** | $ 0.11 | **$ 0.30** | $ 0.49 |
| Distributions to Unitholders | **$ 0.06** | $ 0.23 | **$ 0.75** | $ 0.92 |
| Distributions declared during the period | **$ 0.06** | $ 0.23 | **$ 0.75** | $ 0.92 |

[1] Prior period comparative amounts have been adjusted due to the classification of certain LFG and New England Hydroelectric facilities as Discontinued Operations.

[2] Maintenance expenditures includes plant and equipment expenditures capitalized in accordance with GAAP, which are of a replacement or regulatory nature or represent a major maintenance cost intended to maintain Algonquin's current operations and current level of distributable cash and refunds of developer contributions in Utility Services. The expenditures are amortized over the expected life of the respective asset and the amount amortized in the period is deducted in the calculation of cash available for distribution.

[3] Other includes various non-recurring adjustments including cash available from or used in discontinued operations, gain on sale of capital assets, and any cash generated from operations that may not be available for immediate distribution to unitholders.

The change in cash provided by operating activities after changes in working capital in the year ended December 31, 2008 is primarily due to increased cash generated by operations, increased levels of trade accounts payables, partially offset by lower income from derivative financial instruments, lower interest and other income, and increased interest expense, as compared to the same period in 2007.

Cash available for distribution in the year ended December 31, 2008 was $65.1 million, as compared to $72.3 million in the same period in 2007. The decrease in cash available for distribution is mostly due to lower realized income from derivative financial instruments, lower interest, dividend, and other income, decreased current income taxes and fewer non-recurring distributable cash flow items as compared to the same period in 2007. These decreases were partially offset by increased earnings from operations, as compared to the same period in 2007. In addition, cash available for distribution was reduced by $1.2 million in 2008 due to the commencement of principal repayment of the St. Leon debt facility.

During the year ended December 31, 2008, Algonquin generated $65.1 million ($0.84 per trust unit) in cash available for distribution, as compared to $72.3 million ($0.95 per trust unit) for the same period in 2007. Algonquin distributed $57.8 million ($0.75 per trust unit) during the year ended December 31, 2008, as compared to $69.9 million, ($0.92 per trust unit) for the same period in 2007.

Algonquin's distribution as a percentage of 'Cash available for distribution' ("Payout Ratio") was 88.8% during the year ended December 31, 2008 (2007 – 96.6%).

Cash available for distribution in the quarter ended December 31, 2008 was $18.0 million, as compared to $19.9 million in the same period in 2007. The decrease in cash available for distribution is mostly due to lower realized income from derivative financial instruments, lower interest, dividend, and other income, decreased current income taxes and non-recurring cash flow items, as compared to the same period in 2007. These decreases were partially offset by increased earnings from operations and decreased interest expense, as compared to the same period in 2007. The 'Other – non-recurring cash flow items' realized in the fourth quarter of 2007 primarily relate to the achievement of commercial operation at the St. Leon facility. In addition, cash available for distribution was reduced by $0.4 million in 2008 due to the commencement of principal repayments on the St. Leon debt facility.

During the quarter ended December 31, 2008, Algonquin generated $18.0 million ($0.23 per trust unit) in cash available for distribution, as compared to $19.9 million, ($0.26 per trust unit) for the same period in 2007. Algonquin distributed $4.8 million ($0.6 per trust unit) during the quarter ended December 31, 2008, as compared to $17.5 million ($0.23 per trust unit) in the same period in 2007.

Algonquin's Payout Ratio was 26.5% during the quarter ended December 31, 2008 (2007 – 87.7%).

Distributions paid can be different from distributions declared during a period. Monthly distributions are declared by Algonquin for unitholders of record on the last business day of each month and had been paid within 45 days following each month end. On October 20, 2008, in order to strengthen Algonquin's financial position and support its growth initiatives, commencing with the October 2008 distribution, Algonquin reduced the cash distributions payable to Algonquin's unitholders to $0.24 per unit per annum and reduced the payable period to 15 days following each month end. See the Strategic Realignment section for a more detailed discussion of the change.

## Excess (deficiency) Cash Flows and Net Income Over Distributions Paid

The following chart presents excess or deficiency in cash flows from operating activities and net income over distributions paid for the three and twelve months ended December 31, 2008, and for the years ended December 31, 2007 and 2006.

| | Three months ended December 31 | Year ended December 31 | | |
|---|---|---|---|---|
| | 2008 | 2008 | 2007 | 2006 |
| Cash flow from operating activities | **$ 13,886** | **$ 66,874** | $ 40,427 | $ 69,332 |
| Distributions paid during the period | **(4,774)** | **(57,755)** | (69,923) | (66,955) |
| Excess (shortfall) of cash flows from operating activities over cash distributions paid | **$ 9,112** | **$ 9,119** | $ (29,496) | $ 2,377 |
| Net income (loss) from continuing operations | **(21,095)** | **(19,038)** | $ 24,763 | $ 30,728 |
| Distributions paid during the period | **(4,774)** | **(57,755)** | (69,923) | (66,955) |
| Excess (shortfall) of net income over cash distributions paid | **$ (25,869)** | **$ (76,793)** | $ (45,160) | $ (36,227) |

The shortfall of net income over cash distributions and of cash flows from operating activities over cash distributions have been funded through working capital management, issuing of additional trust units, convertible debenture offerings, cash on hand, or additional borrowings under Algonquin's revolving credit facility.

Algonquin considers the amount of cash generated by the business, cash required for the Company's growth initiatives, funds required to satisfy current or future obligations including taxes in determining sustainable, normalized monthly distributions of cash to its unitholders. In general, Algonquin does not take into account quarterly working capital fluctuations as these tend to be temporary in nature. Algonquin does not generally consider net income in setting the level of distributions as this is a non-cash calculation and does not reflect the level of cash flow generated by Algonquin. In particular Algonquin has a relatively high level of depreciation and amortization expense and has significant volatility in income due to fluctuations from the quarterly mark to market valuations of its hedging instruments and interest rate swaps.

## Summary of Property, Plant and Equipment Expenditures by Business Unit

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2008** | **2007** | **2008** | **2007** |
| **POWER GENERATION & DEVELOPMENT** | | | | |
| **Renewable Energy Division** | | | | |
| Maintenance expenditures | **$ 353** | $ 795 | **$ 1,280** | $ 1,199 |
| Growth and other expenditures | **439** | (6,249) | **8,144** | (6,249) |
| Total | **$ 792** | $ (5,454) | **$ 9,424** | $ (5,050) |
| **Thermal Energy Division** | | | | |
| Maintenance expenditures | **$ 1,212** | $ (51) | **$ 3,457** | $ 2,875 |
| Growth and other expenditures | **1,853** | 10,649 | **4,985** | 23,335 |
| Total | **$ 3,065** | $ 10,598 | **$ 8,442** | $ 26,210 |
| **UTILITY SERVICES BUSINESS UNIT** | | | | |
| Capital Investment in rate baseable Assets | **$ 4,785** | $ 7,384 | **$ 35,712** | $ 19,087 |
| **Consolidated (includes Corporate)** | | | | |
| Maintenance expenditures | **$ 1,713** | $ 897 | **$ 4,995** | $ 4,388 |
| Capital Investment in rate base | **4,785** | 7,384 | **35,712** | 19,087 |
| Growth and other expenditures | **2,291** | 4,399 | **13,128** | 17,085 |
| Total | **$ 8,789** | $ 12,680 | **$ 53,835** | $ 40,560 |

During the year ended December 31, 2008, Algonquin incurred growth and other property, plant and equipment expenditures of $13.1 million, as compared to $17.1 million during the comparable period in 2007. In addition, Utility Services invested $35.7 million in property, plant and equipment during the year ended December 31, 2008, as compared to $19.1 million during the comparable period in 2007.

During the year ended December 31, 2008, the Renewable Energy division's expenditures primarily relate to the Campbellford acquisition, a 4,000 kilowatt hydroelectric generating facility located on the Trent-Severn Waterway approximately four kilometres north of Campbellford, Ontario, and various projects at Great Falls, Clement, Chuteford, Dixon Dam, as well as engineering studies and other preparatory work related to Bill C-93 projects. The change in growth and other expenditures in the prior year primarily relates to final adjustments related to the St. Leon facility achieving commercial operation status in 2007.

During the year ended December 31, 2008, as well as the comparative period, the Thermal Energy division's expenditures primarily relate to the completion of the Sanger re-powering project and investment in the BCI steam sales facility. Included in the division's 2008 fourth quarter growth and other expenditures is a construction supervision and performance fee to APMI of $0.7 million related to its construction management role in the Sanger re-powering project. The Sanger project was completed in the fourth quarter of 2007, while the BCI facility was completed in the second quarter of 2008. Other significant projects include approximately $1.8 million related to projects at the EFW facility and $1.2 million related to the planned equipment maintenance at the Windsor Locks facility in spring 2009, as compared to $2.1 million at EFW and $0.2 million at Windsor Locks in the comparable period.

During the year ended December 31, 2008, as well as the comparative period, Utility Services' capital investment in property, plant and equipment include investments of approximately $24.0 million at the LPSCo facility, including $15.1 million related to additional wells, arsenic treatment and reservoir capacity, and $4.5 million related to waste-water treatment engineering work and operational improvements. Utility Services further invested approximately $1.8 million at the Rio Rico facility primarily related to renovations of existing well capacity and water storage capacity, $1.4 million at the Bella Vista facility primarily related to operational improvements which reduces outages from system failures, and additional underground piping as required by the state transportation department, and $1.0 million at the Black Mountain facility primarily related to the installation and upgrade of a lift station. Utility Services has initiated rate cases at a number of its facilities and the capital projects completed by Utility Services since the last rate cases will be included in the applications. Rate cases are designed to allow a particular facility to appropriately recover its operating costs and earn the rate of return on its capital investment as allowed by the regulatory authority under which the facility operates.

During the quarter ended December 31, 2008, Algonquin incurred growth and other property, plant and equipment expenditures of $2.3 million, as compared to $4.4 million during the comparable period in 2007. In addition, Utility Services invested $4.8 million in property, plant and equipment during the quarter ended December 31, 2008, as compared to $7.4 million during the comparable period in 2007.

Property, plant and equipment expenditures for the 2009 fiscal year are anticipated to be between $15.0 million and $18.0 million, including approximately $2.0 million related to ongoing requirements in Utility Services, $5.0 million related to the Thermal division, and $2.0 million related to the Renewable Energy division. Algonquin also anticipates incurring approximately $3.0 million related to the initial phase of the Windsor Locks repowering and an amount of $3.0 million related to initial anticipated expenditures at the Donnaconna facility related to Bill C-93 in Quebec.

Algonquin anticipates that it can generate sufficient liquidity through internally generated operating cash flows, working capital to finance its property, plant and equipment expenditures and other commitments. Algonquin also has the ability to finance these expenditures through its revolving credit facility as well as through advances from developers.

## Liquidity and Capital Reserves

The following chart sets out the amounts drawn, letters of credit issued and outstanding amounts available to Algonquin under its Facilities:

| | 2008 Q4 | 2008 Q3 | 2008 Q2 | 2008 Q1 | 2007 Q4 |
|---|---|---|---|---|---|
| Total bank credit facility | $ 225,000 | $ 225,000 | $ 225,000 | $ 225,000 | $ 175,000 |
| Less: unexercised accordion | (32,250) | (32,250) | (32,250) | (50,000) | - |
| Committed and available bank credit facilities | $ 192,750 | $ 192,750 | $ 192,750 | $ 175,000 | $ 175,000 |
| Funds Drawn on credit facilities | (137,000) | (144,800) | (150,000) | (140,000) | (126,000) |
| Letters of Credit issued | (37,500) | (33,200) | (31,200) | (27,100) | (25,800) |
| Remaining committed and available bank facilities | **$ 18,250** | **$ 14,750** | **$ 11,550** | **$ 7,900** | **$ 23,200** |
| Cash on Hand | 5,900 | 7,400 | 6,100 | 9,200 | 10,400 |
| **Total liquidity and capital reserves** | **$ 24,150** | **$ 22,150** | **$ 17,650** | **$ 17,100** | **$ 33,600** |

In addition to total liquidity and capital reserves noted above and based on the covenants included in the Facilities, there is an additional $8.8 million of the unexercised accordion feature that would, if exercised, be available to be drawn as at December 31, 2008.

As at December 31, 2008, Algonquin had drawn $137.0 million on its Facilities as compared to $126.0 million as at December 31, 2007. In addition to amounts actually drawn, Algonquin also had $37.5 million in outstanding letters of credit. Therefore, at December 31, 2008, Algonquin had $18.3 million of committed and available bank facilities and $5.9 million of cash, resulting in $24.2 million of total liquidity and capital reserves. Algonquin has strengthened its total liquidity and capital reserves position during the latter half of the fiscal year from $17.7 million to $24.2 million. This improvement is due in part to the reduced cash distributions payable to Algonquin's unitholders commencing with the October 2008 distribution. See the Strategic Realignment section for a more detailed discussion of the change.

The following outlines some of the significant factors influencing liquidity and capital reserves that occurred during the year ended December 31, 2008:

- On January 16, 2008, Algonquin renewed its combined $175.0 million Facilities. Under the terms of the renewal, the Facilities are extended for a three year term with a maturity date of January 14, 2011. The renewal included improved pricing and other terms including covenants and interest rate spreads. The renewed Facilities also contain an accordion feature allowing the Facilities to increase to $225.0 million to accommodate future growth and acquisitions.

- As at December 31, 2008, Algonquin had exercised $17.8 million of the accordion feature and therefore has committed $192.8 million on the Facilities from its bank syndicate. Algonquin has an unexercised amount of $32.3 million remaining on the accordion feature. Based on the covenants included in the Facilities, $8.8 million of the unexercised accordion feature would, if exercised, be available to be drawn as at December 31, 2008. Under the terms of the accordion feature, Algonquin's bank syndicate is not obligated to fund any additional draw requests. In this event, Algonquin is able to bring additional lenders into its banking syndicate. The Facilities also contain covenants which may limit amounts available to be drawn.

- On August 1, 2008, Algonquin issued approximately 3.5 million trust units for gross consideration totalling $27.0 million or $7.69 per unit. In connection with this transaction, Algonquin received:

  (a) cash in an amount of $20.6 million (net of $0.8 million in transaction costs);
  (b) the return of notes having an aggregate face value of approximately $4.8 million that were issued by Algonquin affiliates related to its St. Leon and BCI projects; and
  (c) a note receivable of $0.8 million related to a hydroelectric facility in Ontario.

  The unit issue was pursuant to an agreement entered into on June 27, 2008 between Algonquin, Highground and CJIG. Under the agreement CJIG acquired all of the issued and outstanding common shares of Highground and Algonquin issued approximately 3.5 million trust units of which approximately 3.1 million trust units were received by Highground shareholders as part of the agreement with the remaining trust units being retained by CJIG. Algonquin has recorded the 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 units being recorded at a value of $26.2 million.

  The final consideration for the trust units is dependent on the proceeds realized from the liquidation of certain Highground investments. Algonquin'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, which 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 Algonquin will be determined through negotiation between the trustees of Algonquin 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. Algonquin is entitled to 50% of the ultimate proceeds from these investments, after certain adjustments for transaction costs.

## Contractual Obligations

Information concerning contractual obligations as of March 5, 2009 is shown below:

| | Total | Due less than 1 year | Due 2 to 3 years | Due 4 to 5 years | Due after 5 years |
|---|---|---|---|---|---|
| Long term debt obligations | $ 296,823 | $ 3,233 | $ 211,037 | $ 3,407 | $ 79,146 |
| Interest on Long term debt obligations | $ 132,839 | 20,146 | 39,530 | 21,522 | 51,641 |
| Accounts Payable | $ 34,073 | 34,073 | - | - | - |
| Derivative financial instruments: Currency Forward | $ 16,735 | 3,070 | 10,917 | 2,748 | - |
| Derivative financial instruments: Interest Rate Swap | $ 16,819 | 5,368 | 7,522 | 3,228 | 701 |
| Lease Payments | $ 375 | 102 | 177 | 5 | 91 |
| Other obligations | $ 12,171 | 260 | 515 | 515 | 10,881 |
| Total obligations | $ 509,835 | $ 66,252 | $ 269,698 | $ 31,425 | $ 142,460 |

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

## Unitholders' Equity and Convertible Debentures

As at December 31, 2008, Algonquin had 77,574,372 issued and outstanding trust units with a total of 79,577,201 trust units issued and outstanding on a fully diluted basis.

The Company may issue an unlimited number of trust units. Each trust unit is transferable and represents an equal, undivided beneficial interest in any distribution from the Company and the net assets of the Company. All units are of the same class and with equal rights and privileges and are not subject to future calls or assessments. Each unit entitles the holder to one vote at all meetings of unitholders.

On August 1, 2008, Algonquin 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 June 27, 2008 between Algonquin, Highground and CJIG. Under the agreement CJIG would acquire all of the issued and outstanding common shares of Highground, and Algonquin would issue 3,507,143 trust units, of which 3,065,183 trust units would be received by Highground shareholders as part of the agreement with the remaining trust units being retained by CJIG. (See additional information in the Liquidity section above)

Pursuant to the takeover bid of AirSource Power Fund I LP ("Airsource"), on September 29, 2006 Algonquin issued trust units and a subsidiary issued trust units which are exchangeable into trust units of Algonquin at the holder's option (the "Exchangeable Units"). Algonquin issued 202,536 trust units during the three months ended December 31, 2008 and 422,873 trust units during the year ended December 31, 2008, pursuant to the conversion of Exchangeable Units. As at December 31, 2008, there were 2,002,829 trust units of Algonquin remaining to be issued pursuant to the conversion of Exchangeable Units. Subsequent to December 31, 2008, approximately 63,500 trust units of Algonquin were issued, pursuant to the conversion of Exchangeable Units.

In 2004, Algonquin issued 85,000 convertible unsecured debentures at a price of $1,000 for each debenture. The debentures bear interest at 6.65% per annum and are convertible into trust units of Algonquin 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. Until July 30, 2009, the debentures may be redeemed by Algonquin if the underlying trust unit price is equal to or exceeds a price of $13.31 (125% of the conversion price of $10.65). During the period of July 31, 2009 until the debenture's maturity, Algonquin 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 trust units. As at December 31, 2008, no additional convertible debentures had been presented for conversion and there were 84,964 convertible debentures outstanding.

In November 2006, Algonquin issued 60,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on November 30, 2016. The debentures bear interest at 6.2% per annum and are convertible into trust units of Algonquin 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. The debentures may not be redeemed by Algonquin prior to November 30, 2010. During the period of November 30, 2010 until November 29, 2012, the debentures may be redeemed by Algonquin if the underlying trust unit price is equal to or exceeds a price of $13.75 (125% of the conversion price of $11.00). During the period of November 30, 2012 until the debenture's maturity, Algonquin 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 trust units. As at December 31, 2008, no convertible debentures had been presented for conversion.

## Management of Capital Structure

Algonquin 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.

Algonquin'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 distributions made to unitholders.

- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

Algonquin 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, the Company is currently in the process of reviewing its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries as well as in the context of the change in taxation impacting the Company commencing in 2011.

## Unitholders' Rights Plan

Algonquin has adopted a Unitholders' Rights Plan (the "Plan"). The Plan is designed to ensure the fair treatment of unitholders in any transaction involving a potential change of control of Algonquin and will provide the Board of Trustees and unitholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize unitholder value. The Toronto Stock Exchange (the "Exchange") has accepted notice for filing of the Plan and the Plan was approved by unitholders at Algonquin's annual and special meeting held on April 24, 2008 for a three year period thereafter. The Plan is similar to rights plans adopted by many other Canadian income trusts and corporations. Until the occurrence of certain specific events, the rights will trade with the trust units of Algonquin and be represented by certificates representing the Units. The rights become exercisable only when a person, including any party related to it or acting jointly with it, acquires or announces its intention to acquire twenty percent (20%) or more of the outstanding Units of Algonquin without complying with the Permitted Bid provisions of the Plan. Should a non-Permitted Bid be launched, each right would entitle each holder of Units (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional Units of Algonquin at a fifty percent (50%) discount to the market price at the time.

It is not the intention of the Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Plan, a Permitted Bid is a bid made to all unitholders for all of their Units on identical terms and conditions that is open for no less than 60 days. If at the end of 60 days at least fifty percent (50%) of the outstanding Units, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the Units but must extend the bid for a further ten days to allow all other unitholders to tender.

## Related Party Transactions

The following related party transactions occurred during the year ended December 31, 2008:

- APMI provides management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. In 2008 and 2007, APMI was paid on a cost recovery basis for all costs incurred and charged $0.9 million (2007 - $0.9 million). APMI is 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 2008 $nil (2007 - $0.8 million) was earned by APMI as an incentive fee.
- As part of the project to re-power the Sanger facility, the Company 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 2008, APMI was paid $0.02 million (2007 - $0.1 million) for development supervision. During 2008, the Company accrued $0.7 million as the final fee owed to APMI with respect to this project. This accrued fee is included in accounts payable on the consolidated balance sheet.
- The Company has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a net basis. Lease costs for 2008 were $0.3 million (2007 - $0.3 million).
- On March 10, 2008, Algonquin advanced $0.2 million to the Trustees for purposes of enabling the Trustees to purchase additional Units of Algonquin. The loans are subject to promissory notes issued in favour of Algonquin which are repayable upon demand, currently bear interest at 3% per annum, and are recorded as a reduction in Trust Units on the consolidated balance sheet. During 2008 a principal repayment of $0.01 million was made.

- The Company utilizes chartered aircraft, including the use of an aircraft owned by Airlink, an affiliate of APMI. In 2004, the Company entered into an agreement and remitted $1.3 million to Airlink as an advance against expense reimbursements (including engine utilization reserves) for the Company's business use of the aircraft. Under the terms of this arrangement, the Company 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; such direct operating costs do not provide the affiliate with any profit or return on or of the capital committed to the aircraft. During the year, the Company incurred costs in connection with the use of the aircraft of $0.3 million (2007 - $0.4 million) and amortization expense related to the advance against expense reimbursements $0.1 million (2007 - $0.2 million).
- Up to August 1, 2008, Algonquin had project debt from Highground (previously Algonquin Power Venture Fund) in the amount of $3.0 million related to the St. Leon facility. Highground advanced $1.6 million at a rate of 11.25% as part of the initial financing of the St. Leon facility and advanced $1.4 million at a rate of 9.25% during the first quarter of 2007. These amounts have now been eliminated on the Consolidated Balance Sheet of Algonquin due to the acquisition of Highground.
- Up to July 31, 2008, Highground was paid $0.2 million (2007 - $0.2 million) 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. GWAP, a company controlled by APMI, was paid $0.1 million (2007 - $0.8 million) in 2008 for construction services. In 2008, the Company also paid $nil (2007 - $1.4 million) to GWAP on a cost recovery basis related to ongoing operating expenses of the project.
- Pursuant to the St. Leon Limited Partnership Agreement, in 2006, St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of Airsource and the legal owner of the St. Leon facility, was required to issue 100 Class B units to GWAP. 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 after June 17, 2008, two years after the date the facility achieved commercial operations pursuant to the PPA. Such income allocations and cash distributions shall be increased by 2.5% for each successive 5 year period, to a maximum of 10.0%. 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 holders of the Class B units are entitled to cash distributions of $0.3 million for the year ended December 31, 2008. (2007 - $nil)
- AirSource has agreed to reimburse AirSource Power Fund GP Inc (the "General Partner") of the AirSource Power Fund I LP for reasonable costs incurred by it in acting as registrar and transfer agent and in attending to the administration of AirSource, as required in the Partnership Agreement. The general partner was paid nil during the year ended December 31, 2008 (2007 - $0.01 million).
- Pursuant to the agreement entered into on June 27, 2008 between Algonquin, Highground and CJIG, APMI is entitled to a fee of approximately $0.2 million. This fee has been accrued and is included in accounts payable on the consolidated balance sheet and offset against trust units issued.
- 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 2008, no amounts were paid under this agreement. However, APMI earned a construction supervision fee of $0.1 million in relation to the development of this project.

## Discontinued Operations

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| **Performance (MW-hrs sold)** | - | 19,149 | - | 97,613 |
| **Revenue** | | | | |
| Energy sales | - | 1,233 | - | 6,651 |
| **Expenses** | | | | |
| Operating | - | (1,549) | - | (8,077) |
| **Operating Loss** | - | (316) | - | (1,426) |
| Interest expense | - | (20) | - | (72) |
| Gain on sale of property, plant, equipment and intangible assets | - | 1,414 | - | 2,592 |
| Current income tax expense | - | (1,336) | | (1,336) |
| Future income tax recovery | - | 342 | | 342 |
| Amortization of property, plant, equipment and intangible assets | - | - | - | (1,192) |
| **Net income (loss) from discontinued operations** (including interest and other income) | - | 84 | - | (1,092) |

In December 2007, Algonquin completed the sale of six LFG and six hydroelectric generating facilities. As at December 31, 2007, all assets classified as Discontinued Operations had been sold. These facilities were no longer considered strategic to the ongoing operations of Algonquin.

For the quarter ended December 31, 2008, revenue from Discontinued Operations was nil, as compared to $1.2 million during the same period in 2007. For the year ended December 31, 2008, revenue from Discontinued Operations was nil, as compared to $6.7 million during the same period in 2007.

For the quarter ended December 31, 2008, operating loss was nil, as compared to $0.3 million during the same period in 2007. For the year ended December 31, 2008, operating loss was nil, as compared to $1.4 million during the same period in 2007.

For the quarter ended December 31, 2008, the net income from discontinued operations was nil, as compared to $0.1 million in the comparable period in 2007. For the year ended December 31, 2008, the net loss from discontinued operations was nil, as compared to a $1.1 million loss in the comparable period in 2007.

## Risk Management

Algonquin proactively manages its risk exposures in a prudent manner. Algonquin maintains adequate insurance on all of its facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies such as employee health and safety programs, environmental safety programs, and currency hedging policies to manage its risk exposures.

There are a number of risk factors relating to the business of Algonquin. Some of these risks include the dependence upon Algonquin businesses, regulatory climate and permits, U.S. versus Canadian dollar exchange rates, tax related matters, commodity prices, 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 Algonquin may encounter. A further assessment of Algonquin's business risks is also set out in the 2008 Annual Information Form.

### *Mechanical and operational risks*

Algonquin is entirely dependant upon the operations and assets of Algonquin businesses. Accordingly, distributions to unitholders are dependent upon the profitability of each of Algonquin'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 water utilities operate under pressurized conditions within pressure ranges approved by regulators. Should the 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 Algonquin's operations, both operationally (Renewable Energy, Thermal Energy and Utility Services) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. In addition, Algonquin's existing long term PPAs minimize the risk of reductions in average energy pricing.

### *Regulatory risk*

Profitability of Algonquin businesses is in part dependant on regulatory climates in the jurisdictions in which it operates. In the case of some 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 Algonquin, and while Algonquin 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.

The Company regularly works with these authorities to manage the affairs of the business.

### *Asset Retirement Obligations*

Algonquin completes periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, Algonquin 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, Algonquin does not have any significant retirement obligation liabilities and has not recorded any liability in its financial statements.

Generally, Algonquin'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 Algonquin 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. Algonquin 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 Algonquin has facilities, Algonquin 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 the Company at its option. While Algonquin anticipates being in a position to renew or extend the existing PPA in 2025, in the event that Algonquin is unable to renew or extend the agreement, or identify another purchaser of the energy, the Company may choose to decommission the facility. Algonquin has assessed there to be a remote likelihood of incurring any cost to decommission the wind farm.

The 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 Algonquin anticipates being in a position to renew or extend the existing contract in 2012, in the event that Algonquin is unable to renew or extend the agreement, the Company 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.

The Utility Services business unit's facilities operate under agreements with a state or municipal regulator to provide the sole water distribution and/or waste-water treatment services in its area of operations, as set out in the agreements. In general, these facilities are operated with the assumption that its services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Utility Services 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 waste-water treatment facilities and expenses associated with providing new sources of water can generally be included in the facility's rate base and thus the facility is allowed to earn a return on its investment.

### *Environmental Risks*

Algonquin faces 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. Algonquin has assessed the likelihood of these risks becoming a contingent environmental liability as remote; therefore Algonquin has not recorded any contingent liabilities on its financial statements.

To manage these risks responsibly, Algonquin has Environmental and Compliance departments within the different operating units of the businesses which are responsible for monitoring all of Algonquin's operations, ensuring all operating facilities are in compliance with environmental regulations and preparing regulatory submissions as required. The departments comprise of 7.0 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.

Algonquin's procedures to prevent and minimize any impact of possible oil spills and soil contamination meet generally accepted industry practices. Algonquin's field personnel perform inspections of oil and chemical storage areas on a minimum of a quarterly basis. The Company has 24 hour, 365 day emergency response and spill procedures in place in the event there is an oil or chemical spill.

The Renewable Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a hydroelectric facility include possible dam failure which results in upstream or downstream flooding and equipment failure which results 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, Algonquin 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, Algonquin 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 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, Algonquin 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, Algonquin maintains continuous emissions monitoring systems, performs annual stack testing and completes an annual technical evaluation of ash composition.

The Utility Services business unit 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 waste-water treatment facility include potential air quality and odour management issues, waste-water 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, Algonquin 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 waste-water collection system and at the waste-water 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 and state standards. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Algonquin 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 new standards respecting levels of naturally occurring arsenic in drinking water. Pursuant to the requirements of the drinking water legislation, an additional arsenic treatment system has been placed online at one of LPSCo's reservoir well sites to ensure continued full compliance with the regulatory requirements. The costs of complying with the new standards form part of a facility's rate base for rate case purposes.

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

### *Carbon Disclosure Project*

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.

Algonquin developed a baseline GHG emissions inventory which was submitted 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. At the moment, climate change regulations are in the process of being developed and Algonquin expects that the regulations being developed will eventually apply to Algonquin's Sanger and Windsor Locks facilities but the effect that these regulations may have is not known at this time.

The Carbon Disclosure Project has posted Algonquin's response to the 2008 questionnaire. The CDP report on Canadian responses to the Carbon Disclosure Project 2008 questionnaire was released in Toronto on November 5, 2008. Based on historic CDP reports Algonquin's Power Generation & Development business unit is well positioned to deal with any future climate change regulations. Algonquin's Power Generation & Development business unit emits an average of 3,200 tonnes of CO2 equivalents per $1.0 million U.S. dollars of revenue as compared to a North American Average of 5,000 tonnes of CO2 equivalents per $1.0 million U.S. dollars of revenue.

### *Western Climate Initiative*

Seven U.S. States (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and four Canadian provinces (British Columbia, 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. Algonquin 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 Algonquin and means available to mitigate this financial impact, if any.

## *Specific Environmental Risks*

*Regional Greenhouse Gas Initiative:*

Several North Eastern US States have formed a coordination group to develop a multi state green house gas mitigation action plan. This group is the Regional Greenhouse Gas Initiative ("RGGI"). This group has received backing from several states where Algonquin 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 Algonquin site that is currently affected by the RGGI regulations. As such Algonquin 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. Algonquin is entitled to apply for allowances and/or purchase allowances at a base price of $2.00 per tonne from the state of Connecticut. Algonquin has submitted an application on October 31, 2008 for allowances under the available programs. For 2009, Algonquin has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks facility to be between $350,000 and $500,000.

*Renewable Energy Division:*

As a result of certain legislation passed in Quebec (Bill C93), Algonquin 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 in Quebec. Algonquin 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.

*Utility Services:*

Algonquin owns and operates the LPSCo facility, a water distribution and waste-water treatment utility servicing Litchfield Park, and parts of Goodyear and Avondale, Arizona, where groundwater pollutants originally caused 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 United States Environmental Protection Agency ("EPA") began monitoring these groundwater pollutants in 1981 and has been tracking the gradual underground movement since. In addition to actively participating in EPA focused monthly technical meetings in regards to this monitoring program, LPSCo itself closely monitors its wells for these groundwater pollutants 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 the pollutants in the water from wells used by the utility. In the event that any of the wells which are most immediately at risk exceed permitted contaminant levels, LPSCo would undertake the appropriate action which may include removing the well at risk from the water distribution system of the utility. In this event, there would remain sufficient water flows and reservoir capacity within the balance of the water distribution system to adequately service the needs of all of the customers of the utility. 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 $1.5 million and $3.0 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 groundwater rights. Algonquin does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.

Algonquin'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, 2008.

### *Seasonal fluctuations and hydrology*

The hydroelectric operations of Algonquin 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 Algonquin'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.

### *Foreign currency risk*

Currency fluctuations may affect the cash flows Algonquin would realize from its operations, as certain Algonquin businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such Algonquin businesses also incur costs in U.S. dollars. At Algonquin's current exchange rate, approximately 45% of EBITDA and 60% of cash is generated in U.S. dollars. Algonquin estimates that, on an unhedged basis, a $0.05 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 $5.8 million and increased reported expenses from U.S. operations of approximately $4.1 million or a net impact of $1.7 million ($0.02 per trust unit) on an annual basis.

Algonquin attempts to manage this risk through the use of forward contracts. Algonquin's policy is not to utilize derivative financial instruments for trading or speculative purposes.

At December 31, 2008, the Company had effectively hedged 100% of its expected 2009 U.S. dollar cash flow at $1.13. During the quarter ended December 31, 2008 Algonquin realized a $0.3 million loss on forward contracts settled during the period. During the year ended December 31, 2008 Algonquin realized a $5.1 million gain on forward contracts settled during the period. As at March 5, 2009, Algonquin has total forward contracts to sell U.S. dollars from fiscal 2008 to fiscal 2013 totalling U.S. $115.5 million, carrying an average rate of $1.06.

The following chart sets out the amount of foreign exchange forward contracts, hedge proceeds and average hedged rates over the term of the contracts:

| | Total | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| Total U.S. $ Hedged | $ 115,552 | $ 32,697 | $ 33,165 | $ 29,660 | $ 16,640 | $ 3,390 |
| Total Can. $ Proceeds | $ 122,946 | 36,818 | 34,507 | 30,427 | 17,443 | 3,751 |
| **Unrealized Gain (loss)** | **(16,735)** | **(3,070)** | **(5,668)** | **(5,249)** | **(2,342)** | **(406)** |
| Average Hedged Rate | $ 1.064 | $ 1.127 | $ 1.040 | $ 1.026 | $ 1.048 | $ 1.107 |
| Impact of a $0.05 move in exchange rates | **$ 5,778** | **$ 1,635** | **$ 1,658** | **$ 1,483** | **$ 832** | **$ 170** |

Based on the fair value of the forward contract using the exchange rates as at December 31, 2008, the exercise of these forward contracts will result in the use of $3.1 million in fiscal 2009, the use of cash of $5.7 million in fiscal 2010 and result in the use of cash of $8.0 million for the remainder of the hedged period beyond 2010. Assuming a decrease in the strength of the US dollar relative to the Canadian dollar of $0.05 at December 31, 2008, with a corresponding increase in the forward yield curve, the fair value of the outstanding forward exchange contracts would increase by $5.8 million, reducing the expected use of cash by $1.6 million during fiscal 2009, $1.7 million in fiscal 2010, and $2.5 million for the remainder of the hedged period beyond 2010.

### *Market price risk*

The majority of Algonquin's facilities are subject to long term PPAs. However, certain of the Company's hydroelectric facilities in the New England and New York regions sell energy at current spot market rates. In this regard, each $1.00 change in the market prices per MW-hr would result in a change in revenue of $0.1 million on an annualized basis.

### *Credit/Counterparty risk*

The Company is subject to credit risk through its trade receivables. The Company does not believe this risk to be significant as over 93% of Renewable Energy division's revenue, 83% of Thermal Energy division's revenue, and over 70% 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 Power Generation'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 | 23,900 | 32% |
| Hydro – Quebec | A+ | 22,300 | 29% |
| Ontario Electricity Financial Corporation | A+ | 12,400 | 16% |
| Public Service Company of New Hampshire | BBB | 7,000 | 9% |
| National Grid | A | 5,100 | 7% |
| **Total** | | **$ 70,700** | **93%** |
| **Thermal Energy Division** | | | |
| Connecticut Light and Power Company | BBB | 34,200 | 33% |
| Pacific Gas and Electric Company | BBB+ | 21,800 | 21% |
| Ahlstrom | 1R3 ** | 16,200 | 16% |
| Regional Municipality of Peel | AAA | 16,600 | 13% |
| **Total** | | **$ 88,800** | **83%** |

* Ratings by Standard & Poor's as of February 2009

** Ratings by Dunn & Bradstreet as of February 2009

The remaining revenue is primarily earned by the Utility Services business unit. In this regard, the credit risk related to Utility Services accounts receivable balances of US $2.8 million is spread over approximately 69,000 customers, resulting in an average outstanding balance of less than $50 per customer. 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.

### *Interest rate risk*

Algonquin has 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:

- Algonquin's senior debt facility had a balance of $137.0 million as at December 31, 2008. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $1.4 million annually. During the second quarter of 2008, Algonquin entered into a fixed for floating interest rate swap in an amount of $100.0 million for the period from December 31, 2008 to December 31, 2010, and fixed the interest expense on $100.0 million of borrowings at approximately 3.46% for 2009, and 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 value of the interest rate swap. At December 31, 2008, the fair value of the interest rate swap was a net $5.5 million liability. The mark to market value is calculated based on forward interest rates projections of approximately 0.75% in 2009 and 1.40 % in 2010.

- Algonquin's project debt at the St. Leon facility had a balance of $72.1 million as at December 31, 2008. 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 a variable rate of interest tied to the Canadian bank's prime rate, the Company 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 any changes in interest rates are effectively offset between the change in interest expense and the change in value of the interest rate swap. Algonquin has effectively fixed its interest expense on its senior debt facility at 5.47%. At December 31, 2008, the mark to market value of the interest rate swap was a loss of $11.3 million (December 31, 2007 – gain of $1.2 million). The mark to market value is calculated based on forward interest rates projections of approximately 1.94% over the term of the loan.

- Algonquin's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2008. 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 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.

On October 20, 2008, in order to strengthen Algonquin's financial position and support its growth initiatives, Algonquin reduced the cash distributions payable to Algonquin's unitholders to $0.24 per unit per annum commencing with the October 2008 distribution. See the Strategic Realignment section for a more detailed discussion of the change.

As at December 31, 2008, the Company had cash on hand of $5.9 million and $18.3 million available to be drawn on committed credit facilities from its bank syndicate. See the Liquidity and Capital Reserves section for a more detailed discussion and chart of the funds available to Algonquin under its credit facilities. There is an unexercised amount of $32.25 million remaining on the accordion feature of the credit agreement with its bank syndicate. In addition to total liquidity and capital reserves noted above and based on the covenants included in the Facilities, there is an additional $8.8 million of the unexercised accordion feature that would, if exercised, be available to be drawn as at December 31, 2008.

Algonquin's Facilities and project specific debt total approximately $293.6 million. In the event that Algonquin was required to replace these Facilities with borrowings having less favourable terms or higher interest rates, the level of cash generated for distribution may be negatively impacted. Algonquin attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

The cash available for distribution generated from several of Algonquin's operating facilities are 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 Algonquin losing its investment in such operating facility. Algonquin actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

### *Commodity price risk*

Algonquin'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:

- Algonquin'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 $1.4 million or a net increase in operating profits of approximately $0.2 million.

- Algonquin'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 $2.8 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 $3.3 million or a net increase in operating profits of approximately $0.6 million.

- Algonquin'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.

### *Litigation risks and other contingencies*

Algonquin 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. 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. Anticipated recoveries under existing insurance policies are recorded when assured of recovery.

As reported in previous public filings of Algonquin, Trafalgar Power Inc. and Christine Falls Power Corporation (collectively, "Trafalgar") commenced an action in 1999 in U.S. District Court against Algonquin, APMI and various other entities related to them in connection with the sale of the Trafalgar Class A and B Notes by Aetna Life Insurance Company to Algonquin entities and the Company's foreclosure on the security for the Notes. 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 Algonquin 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 A and B Notes and that Algonquin was therefore the holder and owner of the Notes, and further that all claims asserted by Trafalgar with respect to the transfer of the Notes were without merit. Further, on November 6, 2008, the claims that were remaining in the District Court were dismissed by summary judgement. This decision provides further support for Algonquin's efforts to enforce its rights under the loan documents and the U.S. Bankruptcy Code in the bankruptcy proceeding. On November 21, 2008, Trafalgar requested that the summary judgement be vacated based on alleged new evidence. The new evidence has, in the view of Algonquin, been falsified, and Algonquin has vigorously contested the request and has also taken further investigative steps in relation to the falsification. The motion was submitted for decision by the Court on January 9, 2009. The likelihood of the summary judgement being vacated is low. Following disposition of this motion, an appeal by Trafalgar is expected.

### *Obligations to serve*

Algonquin'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, Algonquin may be required to access capital markets or obtain additional borrowings to finance these future construction obligations.

### *Changes to income tax laws*

Changes to income tax laws and the current tax treatment of mutual fund trusts could negatively impact Algonquin. Although Algonquin is of the view that it currently qualifies under current legislation as a mutual fund trust, there can be no assurance that the legislation will not be changed in the future or that Canada Revenue Agency ("CRA") will agree with this position. If Algonquin ceases to qualify as a mutual fund trust, the return to unitholders may be adversely affected.

On June 22, 2007, Bill C-52 was enacted, which included legislation to impose a tax on certain income distributed to unitholders by certain publicly traded income trusts and partnerships (the "SIFT Rules"). The SIFT Rules apply to "specified investment flow-throughs" ("SIFT") which includes trusts resident in Canada whose units are listed or traded on a stock exchange or other public market if the trust holds one or more "non-portfolio properties" .

Algonquin is a SIFT trust as defined under the SIFT Rules. Algonquin would have been a SIFT trust on October 31, 2006 had the SIFT Rules been in force on that date. The SIFT rules will not apply to

Algonquin until its first taxation year that ends in 2011 or, if earlier, that includes the first day after December 15, 2006 on which Algonquin exceeds normal growth guidelines (the "Guidelines") issued by the Department of Finance on December 15, 2006 , revised on December 5, 2008 and as may be further amended from time to time. Provided Algonquin does not exceed normal growth as determined by the Guidelines, the SIFT Rules will apply to Algonquin starting with the 2011 taxation year.

Based on the current legislation, a possible interpretation of the SIFT Rules exists under which Algonquin's subsidiary trusts and partnerships may also be viewed as SIFTs. The precise impact of these technical issues cannot be determined until the Canada Revenue Agency provides detailed administrative policies regarding the interpretation of the SIFT Rules and their application to trusts and partnerships in which a publicly traded trust holds a direct or indirect interest. On December 20, 2007, the Minister of Finance announced his intention to introduce technical amendments to the SIFT definition to exclude certain flow through subsidiaries of a SIFT that are able to meet certain ownership conditions. Specifically, the SIFT definition will be amended to exclude trusts and partnerships whose equity is not publicly traded, and is wholly owned by a SIFT, a REIT, a taxable Canadian corporation, another entity meeting this test, or any combination of these types of entities. Draft legislation in respect of these technical amendments is included in Bill C-10, which received first reading on February 6, 2009, but as yet has not been enacted. Algonquin has a subsidiary partnership that may not meet this ownership requirement and therefore this entity may be subject to SIFT tax commencing in 2011, or earlier if it exceeds its normal growth guidelines.

Once the SIFT Rules apply, Algonquin will not be entitled to any deduction in computing its income in respect of any part of its distributions to unitholders that are attributable either to a business it carries on in Canada or to income (other than dividends from taxable Canadian corporations) from, or capital gains in respect of, non-portfolio properties ("non-portfolio earnings"). Non-portfolio properties include investments in a "subject entity". The main kinds of subject entities are corporations and trusts resident in Canada and partnerships which meet certain residence related criteria. Generally, a subject entity will be a non-portfolio property if Algonquin holds securities of the entity that have a fair market value that is greater than 10% of the entity's equity value of more than 50% of the equity value of Algonquin is attributable to the subject entity and affiliated entities.

Once the SIFT Rules apply, Algonquin will be subject to tax in respect of non-portfolio earnings which it distributes at a rate that is equivalent to the general corporate tax rate. Any non-portfolio earnings distributed by Algonquin will be taxable to the Unitholder as if the distribution were a taxable dividend from a taxable Canadian corporation and will be deemed to be an "eligible dividend" eligible for the enhanced gross-up and tax credit.

If the SIFT Rules apply to Algonquin in 2011 it is anticipated that generally the tax paid by Algonquin and a Unitholder who is a taxable Canadian resident individual on distributed non-portfolio earnings would be substantially equivalent to the tax that would be payable on such distributions by such a Unitholder if the SIFT Rules were not enacted. Non-resident unitholders and Canadian resident unitholders which are exempt from tax would be negatively affected by the application of the SIFT Rules based on Algonquin's current investments.

Although Algonquin is of the view that all expenses being claimed by Algonquin are reasonable and that the cost amount of Algonquin's depreciable properties have been correctly determined, there can be no assurance that CRA 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 unitholders.

## Critical Accounting Estimates

Algonquin prepared its Consolidated Financial Statements in accordance with GAAP. An understanding of Algonquin'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 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. Algonquin regularly evaluates the assumptions and estimates that are used in the preparation of the Company'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.

Algonquin recognizes revenue derived from energy sales at the time energy is delivered. Utility Services revenue is recognized when processed and delivered to customers. 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.

Algonquin records as other liabilities amounts received by Utility Services 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 Algonquin'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.

Algonquin also regularly assesses 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 Algonquin will not be able to recover the assets entire carrying value. Should impairment be deemed to have occurred, Algonquin would reduce the carrying value of that asset in the financial statements and deduct this amount from earnings. Algonquin 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

Algonquin's management is responsible for preparation and presentation of the Consolidated Financial Statements and MD&A. Algonquin'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 the Company'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 the Company 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 the Company'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 the Company 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, 2008, based on the framework set forth in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). 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, 2008 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, 2008.

| *Millions of dollars (except per trust unit amounts)* | 1st Quarter 2008 | 2nd Quarter 2008 | 3rd Quarter 2008 | 4th Quarter 2008 | Total |
|---|---|---|---|---|---|
| Revenue | $ 48.0 | $ 54.2 | $ 55.1 | $ 56.5 | $ 213.8 |
| Net earnings / (loss) from continuing operations | (1.6) | 8.0 | (4.4) | (21.1) | ( 19.1) |
| Net earnings / (loss) | (1.6) | 8.0 | (4.4) | (21.1) | ( 19.1) |
| Net earnings / (loss) from continuing operations per trust unit | (0.02) | 0.10 | (0.06) | (0.27) | ( 0.25) |
| Net earnings / (loss) | (0.02) | 0.10 | (0.06) | (0.27) | ( 0.25) |
| Total Assets | 950.7 | 952.2 | 963.8 | 978.1 | 978.1 |
| Long term debt* | 460.6 | 469.6 | 460.9 | 462.9 | 462.9 |
| Distribution per trust unit | 0.23 | 0.23 | 0.23 | 0.06 | 0.75 |

| | 1st Quarter 2007 | 2nd Quarter 2007 | 3rd Quarter 2007 | 4th Quarter 2007 | Total |
|---|---|---|---|---|---|
| Revenue | $ 47.6 | $ 47.8 | $ 46.5 | $ 44.3 | $ 186.2 |
| Net earnings from continuing operations | 6.9 | (2.6) | 13.0 | 7.5 | 24.8 |
| Net earnings | 6.2 | (2.3) | 12.2 | 7.6 | 23.7 |
| Net earnings from continuing operations per trust unit | 0.09 | (0.04) | 0.17 | 0.12 | 0.34 |
| Net earnings per trust unit | 0.08 | (0.03) | 0.16 | 0.10 | 0.31 |
| Total Assets | 1,035.8 | 1,049.0 | 1,024.1 | 954.1 | 954.1 |
| Long term debt* | 401.8 | 410.0 | 421.0 | 445.1 | 445.1 |
| Distribution per trust unit | 0.23 | 0.23 | 0.23 | 0.23 | 0.92 |

* 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 $56.5 million and $44.3 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. There are two additional significant factors impacting revenues year over year. The fluctuation in the strength of the Canadian dollar has resulted in significant changes in reported revenue from U.S. operations, as well as realized gains on financial instruments were recorded as revenue in the comparable quarters of 2007. Additionally, revenue has generally trended up due to facility acquisitions, including the St. Leon wind facility in September 2006, and organic growth in the Utility Services business unit.

Quarterly net earnings have fluctuated between net earnings of $13.0 million and a net loss of $21.1 million over the prior two year period. Recent 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 Algonquin's adoption of Section 3855 and the discontinuation of hedge accounting under Section 3865.

## Changes in Accounting Policies

Algonquin's accounting policies are described in Note 1 to the Consolidated Financial Statements for the year ended December 31, 2008. There have been no changes to the critical accounting policies as disclosed in Algonquin's audited Consolidated Financial Statements for the year ended December 31, 2008. Algonquin has adopted the new standards for Capital Disclosures CICA Handbook Section 1535 as well as CICA Handbook Sections 3862 Financial Disclosures and 3863 Financial Instruments – Disclosure and Presentation. These new standards, more fully described below, require disclosure on financial instruments and related risks but have no impact on the classification or measurement of the Algonquin's consolidated financial statements.

## *Capital Disclosures*

In December 2006, the CICA issued Handbook Section 1535, Capital Disclosures, which establishes standards for disclosing information about an entity's capital and how it is managed. The entity's disclosure should include information about its objectives, policies and processes for managing capital and disclose whether or not it has complied and the consequences of non-compliance with any capital requirements to which it is subject. The new standard was effective on January 1, 2008. Algonquin has set out this disclosure in this MD&A and the accompanying financial statements.

## *Future Accounting Changes not yet Adopted*

### *General Standards on Financial Statement Presentation*

CICA Handbook Section 1400, General Standards on Financial Statement Presentation, has been amended to include requirements to assess and disclose an entity's ability to continue as a going concern. The changes are effective for the Company for interim and annual financial statements beginning April 1, 2008. The adoption of this standard is not expected to have any material impact on the consolidated financial statements.

### *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*

In January 2009, the CICA issued EIC 173, Credit Risk and the 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 is effective and is to be applied retrospectively without restatement of prior periods to all financial assets and liabilities measured at fair value in interim and annual financial statements for periods ending on or after the date of issuance of this Abstract. The Company 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. The Company 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. The Company is currently evaluating the impact of adopting this standard on its consolidated financial statements.

### *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. 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. The Company is currently evaluating the impact of adopting this standard on its consolidated financial statements.

*Goodwill and Intangible Assets*

In February 2008, the CICA issued Handbook Section 3064, Goodwill and Intangible Assets, replacing section 3062, Goodwill and Other Intangible Assets, and Section 3450, Research and Development Costs. This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. The new section is effective for years beginning on or after October 1, 2008. The Company has not yet determined the impact that the adoption of this change will have on its consolidated financial statements.

*Changeover to International Financial Reporting Standards*

In 2011, Algonquin 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, Algonquin will report quarterly comparative financial information using IFRS. The exact impact on Algonquin's financial statements of moving to IFRS is not completely known at this time; however, one area of potential change may involve the valuation of property, plant and equipment on the balance sheet. 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.

In this regard, the Company is currently developing a conversion plan in order to ensure that it is prepared for the conversion and to minimize any disruption the conversion may cause. We note that this conversion plan is subject to change as a result of ongoing and subsequent changes to IFRS standards and interpretations. Algonquin's key personnel have received and will continue to invest in various training courses with regards to IFRS rules and the impact it will have on Algonquin's reporting requirements. In addition, Algonquin has initiated 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 on Algonquin and considers the difficulties surrounding the application of IFRS.

With regards to the impact of IFRS on Algonquin's banking and other financial covenants, Algonquin's senior secured revolving operating and acquisition credit facilities mature on January, 14, 2011. Accordingly, Algonquin will be in a position to review and amend any financial covenants impacted by IFRS during the renewal process.

Algonquin is currently looking to hire a specialist to co-ordinate and manage the changeover process. Once the training has been completed, a more detailed conversion plan will be developed.

The Company's Audit Committee is involved with this process and will be provided formal updates on a quarterly basis and as required.

# AUDITORS' REPORT TO UNITHOLDERS

We have audited the consolidated balance sheets of Algonquin Power Income Fund as at December 31, 2008 and 2007 and the consolidated statements of operations, deficit, comprehensive income/(loss) and accumulated other comprehensive income/(loss) and cash flows for the years then ended. These financial statements are the responsibility of the Fund'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. 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 Fund as at December 31, 2008 and 2007 and the results of its operations and its 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 4, 2009

# Consolidated Balance Sheets

**December 31, 2008 and 2007**

*(thousands of Canadian dollars)*

| | | 2008 | | 2007 |
|---|---|---|---|---|
| **ASSETS** | | | | |
| Current assets: | | | | |
| Cash | $ | 5,902 | $ | 10,361 |
| Accounts receivable | | 28,138 | | 26,597 |
| Prepaid expenses | | 2,832 | | 3,052 |
| Current portion of notes receivable (note 5) | | 485 | | 421 |
| Current portion of derivative assets | | - | | 7,857 |
| | | 37,357 | | 48,288 |
| Long-term investments and notes receivable (note 5) | | 27,134 | | 30,047 |
| Future non-current income tax asset | | 2,894 | | 2,416 |
| Property, plant and equipment (note 6) | | 804,965 | | 760,677 |
| Intangible assets (note 7) | | 97,398 | | 99,529 |
| Restricted cash | | 5,295 | | 6,105 |
| Deferred costs | | 243 | | 80 |
| Other assets (note 4) | | 2,844 | | 2,737 |
| Derivative assets | | - | | 4,188 |
| | $ | 978,130 | $ | 954,067 |
| **LIABILITIES AND UNITHOLDERS' EQUITY** | | | | |
| Current liabilities: | | | | |
| Accounts payable and accrued liabilities | $ | 34,074 | $ | 27,007 |
| Distributions payable | | 1,587 | | 11,649 |
| Current portion of long-term liabilities (notes 10 and 12) | | 4,236 | | 1,915 |
| Current portion of derivative liabilities (note 8) | | 8,438 | | - |
| Current income tax liability (note 14) | | 541 | | 669 |
| Future income tax liability | | 1,191 | | 756 |
| | | 50,067 | | 41,996 |
| Long-term liabilities (notes 9 and 10) | | 293,590 | | 281,725 |
| Convertible debentures (note 11) | | 140,427 | | 139,587 |
| Other long-term liabilities (note 12) | | 28,859 | | 23,771 |
| Future non-current income tax liability (note 14) | | 85,654 | | 80,785 |
| Derivative liabilities (note 8) | | 25,116 | | - |
| Non controlling interest | | 12,548 | | 21,700 |
| Unitholders' equity: | | | | |
| Trust units (note 13) | | 722,215 | | 692,213 |
| Deficit | | (358,904) | | (283,820) |
| Accumulated other comprehensive income | | (21,442) | | (43,890) |
| | | 341,869 | | 364,503 |
| Commitments and contigencies (note 18) | | | | |
| | **$** | 978,130 | **$** | 954,067 |

See accompanying notes to consolidated financial statements

Approved bv the Trustees

Ken Moore

George Steeves

# Consolidated Statements of Operations

**For the years ended December 31, 2008 and 2007**

*( thousands of Canadian dollars, except per unit amounts)*

| | 2008 | 2007 |
|---|---|---|
| **Revenue:** | | |
| Energy sales | $ 158,508 | $ 116,565 |
| Waste disposal fees | 15,706 | 13,609 |
| Water reclamation and distribution | 35,233 | 33,699 |
| Other revenue (note 23) | 4,349 | 22,302 |
| | 213,796 | 186,175 |
| **Expenses** | | |
| Operating | 120,479 | 99,314 |
| Amortization of property, plant and equipment | 36,541 | 34,278 |
| Amortization of intangible assets | 7,305 | 7,287 |
| Management costs (note 16) | 893 | 1,637 |
| Administrative expenses | 9,419 | 8,463 |
| (Gain) / loss on foreign exchange | 4,018 | (7,688) |
| | 178,655 | 143,291 |
| **Earnings before undernoted** | 35,141 | 42,884 |
| Interest expense | 26,288 | 26,565 |
| Interest, dividend income and other income (note 22) | (7,023) | (9,408) |
| Write down of note receivable (note 5) | - | 726 |
| (Gain) / loss on derivative financial instruments (note 15) | 37,748 | (14,469) |
| | 57,013 | 3,414 |
| **Earnings / (loss) from operations before income taxes, minority interest and discontinued operations** | (21,872) | 39,470 |
| **Income tax provision (recovery) (note 14)** | | |
| Current | (184) | (310) |
| Future | 492 | 15,418 |
| | 308 | 15,108 |
| Minority interest in losses of subsidiaries | (3,142) | (401) |
| **Net earnings / (loss) from continuing operations** | (19,038) | 24,763 |
| **Net earnings / (loss) from discontinued operations (note 17)** | - | (1,092) |
| **Net earnings / (loss)** | $ (19,038) | $ 23,671 |
| Basic net earnings / (loss) from continuing operations per trust unit (note 21) | $ (0.25) | $ 0.34 |
| Diluted net earnings / (loss) from continuing operations per trust unit (note 21) | $ (0.25) | $ 0.32 |
| Basic and diluted net loss from discontinued operations per trust unit (note 21) | $ - | $ (0.01) |
| Basic net earnings / (loss) per trust unit (note 21) | $ (0.25) | $ 0.32 |
| Diluted net earnings / (loss) per trust unit (note 21) | $ (0.25) | $ 0.31 |

See accompanying notes to consolidated financial statements

# Consolidated Statements of Cash Flows

**For the years ended December 31, 2008 and 2007**

*( thousands of Canadian dollars )*

| | 2008 | 2007 |
|---|---|---|
| **Cash provided by (used in):** | | |
| **Operating Activities:** | | |
| Net earnings / (loss) from continuing operations | $ (19,038) | $ 24,763 |
| Items not affecting cash: | | |
| Amortization of property, plant and equipment | 36,541 | 34,278 |
| Amortization of intangible assets | 7,305 | 7,287 |
| Other amortization | 1,130 | 2,039 |
| Distributions received in excess of equity income | 680 | - |
| Future income taxes | 492 | 15,418 |
| Unrealized loss / (gain) on derivative financial instruments | 42,426 | (4,862) |
| Write down of note receivable | - | 726 |
| Gain on sale of note receivable and other assets | (918) | - |
| Minority interest | (3,429) | (401) |
| Unrealized foreign exchange (gain) / loss on long term debt | 6,018 | (8,077) |
| | 71,207 | 71,171 |
| Changes in non-cash operating working capital | (4,333) | (30,744) |
| | 66,874 | 40,427 |
| **Financing Activities:** | | |
| Cash distributions | (56,046) | (67,416) |
| Cash distributions to non-controlling interest | (1,709) | (2,516) |
| Trustee loans (note 16) | (218) | - |
| Deferred financing costs | (463) | (158) |
| Increase in long term liabilities | 64,300 | 71,400 |
| Decrease in long term liabilities | (55,873) | (11,836) |
| Increase / (decrease) in other long term liabilities | 5,314 | (1,345) |
| | (44,695) | (11,871) |
| **Investing Activities:** | | |
| Decrease / (increase) in restricted cash | 1,787 | (295) |
| Decrease/ (increase) in other assets | 637 | (1,241) |
| Proceeds on sale of note receivable | 2,954 | - |
| Receipt of principal on notes receivable | 517 | 1,319 |
| Increase in long term investments | (191) | (950) |
| Proceeds from sale of property, plant and equipment and intangible assets | - | 14,083 |
| Net additions to property, plant and equipment | (45,561) | (39,571) |
| Acquisition of Highground (note 3(a)) | 20,617 | - |
| Acquisitions of operating entities (note 3(b) and 3(d)) | (8,274) | (990) |
| | (27,514) | (27,645) |
| Effect of exchange rate differences on cash | 876 | (1,181) |
| Increase /(decrease) in cash from continuing operations | (4,459) | (270) |
| Increase / (decrease) in cash from discontinued operations | - | (2,834) |
| Cash, beginning of the period | 10,361 | 13,465 |
| Cash, end of the period | $ 5,902 | $ 10,361 |
| | - | |
| **Supplemental disclosure of cash flow information:** | | |
| Cash paid during the period for interest expense | $ 26,160 | $ 25,599 |
| Cash paid during the period for income taxes | $ 1,336 | $ 515 |

See accompanying notes to consolidated financial statements

# Consolidated Statements of Deficit

**For the years ended December 31, 2008 and 2007**

*(thousands of Canadian dollars)*

| | 2008 | 2007 |
|---|---|---|
| Balance, beginning of period | $ (283,820) | $ (239,967) |
| Net earnings / (loss) | (19,038) | 23,671 |
| Distributions | (56,046) | (67,524) |
| Balance, end of period | $ (358,904) | $ (283,820) |

See accompanying notes to consolidated financial statements

# Consolidated Statements of Comprehensive Income / (Loss) and Accumulated Other Comprehensive Income / (Loss)

**For the years ended December 31, 2008 and 2007**

(thousands of Canadian dollars)

| | | 2008 | | 2007 |
|---|---|---|---|---|
| **Net earnings / (loss)** | $ | (19,038) | $ | 23,671 |
| **Other comprehensive income (loss):** | | | | |
| Forward exchange contracts settled in the period | $ | (3,173) | $ | (6,206) |
| Translation of self sustaining foreign operations | | 25,621 | | (48,851) |
| Other comprehensive income (loss) | | 22,448 | | (55,057) |
| Total comprehensive income / (loss) | $ | 3,410 | $ | (31,386) |
| **Accumulated other comprehensive income / (loss):** | | | | |
| Balance, beginning of the period | $ | (43,890) | $ | 11,167 |
| Other comprehensive income / (loss) | | 22,448 | | (55,057) |
| Balance, end of the period | $ | (21,442) | $ | (43,890) |

See accompanying notes to consolidated financial statements

Algonquin Power Income Fund (the “Fund” or the “Company”) is an open-ended, unincorporated trust established pursuant to its Declaration of Trust dated September 8, 1997, as amended, under the laws of the Province of Ontario. The Fund’s principal activity is the ownership, directly or indirectly, 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. The revolving credit facility and the convertible debentures are direct obligations of the Fund.

Distributions are made on a monthly basis at the discretion of the Trustees of the Fund (note 20).

The Fund is managed by Algonquin Power Management Inc. (“APMI”). An entity owned by the majority of the shareholders of APMI is the general partner of Algonquin Airlink Limited Partnership which owns an aircraft that the Fund charters. An entity owned by the shareholders of APMI is the general partner of Algonquin Property LP which leases the corporate office to the Fund. GreenWing Algonquin Power Development Inc. (“GWAP”), an entity majority owned by APMI, provides construction services. Collectively, these entities are referred to as the Algonquin Power Group.

In addition to the Fund’s Power Generation business unit, the Fund’s Utility Services business unit 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 consolidated financial statements of the Fund have been prepared in accordance with accounting principles generally accepted in Canada and include the consolidated accounts of all of its subsidiaries and variable interest entities where the fund is the primary beneficiary.

All significant intercompany transactions and balances have been eliminated.

(b) Cash:

Cash includes cash deposited at banks and highly-liquid investments with original maturities of 90 days or less.

(c) Restricted cash:

Cash reserves segregated from the Fund’s cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. The Fund cannot access restricted cash without the prior authorization of parties not related to the Fund.

**1. Significant accounting policies: (continued)**

(d) 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.

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.

(e) 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.

(f) Impairment of long-lived assets:

The Fund 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.

(g) Other long-term liabilities:

Other long-term liabilities include advances in aid of construction. Certain of the Fund'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. The Fund 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 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. An average rate was estimated over the life of the lease is being expensed over the lease term and the resultant deferred water rights amount recorded in the first ten years is being drawn down in the last forty years.

**1. Significant accounting policies: (continued)**

(g) Other long-term liabilities: (continued)

Other long term liabilities also include customer deposits. Customer deposits result from the Utility Services Division 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.

(h) Deferred costs:

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

(i) Long-term investments:

Investments in which the Fund has significant influence but not control or joint control are accounted using the equity method. The Fund records its share in the income or loss of its investees in interest, dividend and other income in the consolidated statement of earnings and deficit. All other equity investments and notes receivable where the Fund 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.

(j) 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 and 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.

(k) Foreign currency translation:

The Fund's policy for translation of foreign operations depends on whether the foreign operations are considered integrated or self-sustaining. Prior to October 1, 2007, all of the Fund's foreign operations were 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.

**1. Significant accounting policies: (continued)**

(k) Foreign currency translation: (continued)

The ongoing review of the economic factors to be considered in determining whether foreign operations are integrated or self-sustaining has resulted in the determination that the Fund's operating entities in the Utility Services Division have changed to self-sustaining. This change was made as a result of the Utility Services Division entities' increasing proportion of operating, financing and investing transactions that are denominated in currencies other than the Canadian dollar. This change in method was effective at October 1, 2007 and was applied prospectively. 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 operations of self-sustaining operations are reported as a component of Other Comprehensive Income in the Consolidated Statement of Comprehensive Income.

The Fund's remaining United States subsidiaries and partnership interests continue to be considered as functionally integrated with the Canadian operations and accounted for as integrated foreign operations.

(l) 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 Fund's assessments the Company does not have any significant asset retirement obligations and therefore no provision for retirement obligations has been recorded in 2008 and 2007.

(m) 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 existing 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.

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.

**1. Significant accounting policies: (continued)**

(n) Financial instruments

The Fund has classified its cash, accounts receivable, restricted cash, accounts payable and distribution 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. The Fund 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.

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.

The Fund has entered into forward foreign exchange contracts to manage its exposure to the US dollar as significant cash flows are generated in the US. Under these forward exchange contracts, the Fund 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, the Fund 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, 2008 included in accumulated other comprehensive income is a gain of $1,789 related to these foreign exchange contracts (2007 – a loss of $4,962).

In 2006, 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 credit facility in order to reduce the interest rate variability on its senior debt facility. The Fund 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.

**1. Significant accounting policies: (continued)**

(o) 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 aid-in construction payments that will not be repaid, 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 1535 - Capital Disclosures

Effective January 1, 2008, the Company adopted the CICA Handbook Section 1535, Capital Disclosures which establishes guidelines for disclosure of both qualitative and quantitative information that enables users of financial statements to evaluate the entity's objectives, policies and processes for managing capital. This section relates to disclosure and presentation only and did not have an impact on financial results.

(b) CICA Section 3862 - Financial Instruments - Disclosure, and
CICA Section 3863 - Financial Instruments - Presentation

Effective January 1, 2008, the Company adopted the CICA Handbook Section 3862, Financial Instruments - Disclosure, and CICA Handbook Section 3863, Financial Instruments – Presentation. CICA Handbook Section 3862 describes the required disclosure for the assessment of the significance of financial instruments for an entity's financial position and performance and of the nature and extent of risks arising from financial instruments to which the entity is exposed and how the entity manages those risks. CICA Handbook Section 3863 establishes standards for presentation of the financial instruments and non-financial derivatives. It carries forward the presentation related requirements of Section 3861, Financial Instruments - Disclosure and Presentation. These sections relate to disclosure and presentation only and did not have an impact on financial results.

(c) CICA Section 3064 – Goodwill and intangible assets

In February 2008, the CICA issued 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 new section will become effective on January 1, 2009 for the Company. The Company is currently evaluating the effect of the adoption of this new standard on the consolidated financial statements.

**2. Adoption of new accounting standards (continued)**

(d) CICA Section – 1400 – General Standards on Financial Statement Presentation

CICA Handbook Section 1400, General Standards on Financial Statement Presentation, has been amended to include requirements to assess and disclose an entity's ability to continue as a going concern. The changes are effective on January 1, 2008 for the Company.

(e) CICA Section 1582 – 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. The Company is currently evaluating the impact of adopting this standard on its consolidated financial statements.

(f) CICA Section 1602 – 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. The Company is currently evaluating the impact of adopting this standard on its consolidated financial statements.

(g) CICA Section 1601 – 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. The Company is currently evaluating the impact of adopting this standard on its consolidated financial statements.

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

In January 2009, the CICA issued EIC 173, Credit Risk and the 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 is to be applied retrospectively without restatement of prior periods to all financial assets and liabilities measured at fair value in interim and annual financial statements for periods ending on or after the date of issuance of this Abstract. The Company is currently evaluating the impact of adopting this standard on its consolidated financial statements.

## 3. Acquisitions

### (a) Highground Capital Corporation

On August 1, 2008, the Company 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, the managers of the Company. Under the agreement, CJIG acquired all of the issued and outstanding common shares of Highground and Algonquin 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.

The Company's final consideration for the trust units 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 which 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 trustees of the Company and CJIG.

The Company 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, 2008, the Company received consideration and issued trust units as follows:

| | |
|---|---|
| Consideration received: | |
| Cash | $20,617 |
| 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 |
| | $26,203 |
| | |
| Trust units issued: | |
| Trust units issued | $26,970 |
| Transaction costs | (767) |
| | $26,203 |

The Fund's 50% share of any additional proceeds from liquidation of the remaining Highground assets will be recorded as additional proceeds from the issuance of units in future periods.

Included in transaction costs is a fee of $240 payable to APMI in respect of its role in completing the transaction (see note 16).

## 3. Acquisitions (continued)

(b) 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.

(c) Entrada Del Oro Sewer Company

On August 30, 2008, the Company entered into an agreement to acquire the shares of Entrada Del Oro Sewer Company located in Phoenix Arizona, for $707 (US $670) in the Utility Services division. Subject to certain limitations and conditions, the Company will also pay the vendor for additional customers connected with Entrada Del Oro over the next ten years. The acquisition requires formal approval from the regulator in the state of Arizona, therefore this amount has been included in other assets on the consolidated balance sheet at December 31, 2008.

(d) Rio Rico Utilities, Litchfield Park Service Company, and Woodmark Utility Company

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

**3. Acquisitions (continued)**

(d) Rio Rico Utilities, Litchfield Park Service Company, and Woodmark Utility Company (continued))

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

| | | **2008** | | **2007** |
|---|---|---|---|---|
| Rio Rico | $ | 418 | $ | 357 |
| LPSCO | | - | | 271 |
| Woodmark | | - | | 103 |
| | $ | 418 | $ | 731 |
| In United States dollars | $ | 405 | $ | 668 |

As of December 31, 2008 the Fund accrued $418 (2007 - $731) as a growth premium, and increased intangible assets by a similar amount, including an amount calculated for future income taxes of $nil (2007 - $171). For Rio Rico, these payments ended in 2008. For LPSCO and Woodmark, these payments ended in 2007.

(e) Assets and regulatory licences near the Town of Sierra Vista, Arizona

On February 13, 2007 Southern Sunrise Water Company Inc, and Northern Sunrise Water Company Inc. both indirect wholly owned subsidiaries of the Fund, completed the acquisition of the assets and regulatory licences related to the provision of water distribution utility services to approximately 1,500 water distribution customers located near the Town of Sierra Vista, Arizona for cash consideration of $816 (US$698). The Fund also incurred $348 (US$300) of acquisition costs. At December 31, 2006, the Fund had $582 (US$498) in escrow pending the approval of regulatory authorities. A deposit in the amount of $234 (US$200) was paid in 2004 which was recorded in deferred costs.

The acquisitions have been accounted for using the purchase method, with earnings from operations included in the Consolidated Statements of Operations since the date of acquisition. The consideration paid by the Fund has been allocated to net assets acquired as follows:

| | | |
|---|---|---|
| Property, plant and equipment | $ | 1,164 |
| Total purchase price | $ | 1,164 |
| | | |
| Consideration: | | |
| Prior year deposit paid | $ | 234 |
| Funds released from escrow | | 582 |
| Acquisition costs | | 348 |
| Total purchase price consideration | $ | 1,164 |

## 4. Other assets

Other assets consist of the following:

| | | 2008 | | 2007 |
|---|---|---|---|---|
| Deferred rate case costs | $ | 1,155 | $ | 1,166 |
| Entrada Del Oro acquisition deposit (note 3 (c)) | | 820 | | - |
| Wind development assets | | 709 | | 1,381 |
| Other | | 160 | | 190 |
| | $ | 2,844 | $ | 2,737 |

Deferred rate case costs relate to costs incurred by the Fund'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.

## 5. Long-term investments and notes receivable

Long-term investments consist of the following:

| | | 2008 | | 2007 |
|---|---|---|---|---|
| Long term investments: | | | | |
| Non-controlling equity and debt interest in three (2007 – four) power generating facilities, recorded at cost | $ | 20,777 | $ | 23,902 |
| A 45% partnership interest in the Algonquin Power (Rattle Brook) Partnership | | 3,881 | | 3,838 |
| A 50% partnership interest in the Campbellford Limited Partnership (note 3(b)) | | - | | 715 |
| | | 24,658 | | 28,455 |
| Notes receivable: | | | | |
| Airlink Advance (note 16) | | 818 | | 908 |
| Twin Falls (note 3(a)) | | 783 | | - |
| Other | | 1,359 | | 1,105 |
| | | 2,960 | | 2,013 |
| | | 27,618 | | 30,468 |
| Less: current portion | | (485) | | (421) |
| Total long term investments and notes receivable | $ | 27,134 | $ | 30,047 |

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

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

In 2007, the Fund wrote off the remaining $726 principle balance of the Across America note which matured January 31, 2008. The balance at December 31, 2008 was $nil.

## 6. Property, plant and equipment

Property, plant and equipment consist of the following:

**2008**

| | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Land | $ 11,154 | $ - | $ 11,154 |
| Facilities | 979,896 | 195,120 | 784,776 |
| Equipment | 27,855 | 18,820 | 9,035 |
| | $ 1,018,905 | $ 213,940 | $ 804,965 |

**2007**

| | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Land | $ 10,008 | $ - | $ 10,008 |
| Facilities | 895,674 | 156,460 | 739,214 |
| Equipment | 26,390 | 14,935 | 11,455 |
| | $ 932,072 | $ 171,395 | $ 760,677 |

Facilities include cost of $94,606 (2007 - $94,606) and accumulated amortization of $22,889 (2007 - $20,400) related to facilities under capital lease, and $13,200 (2007 - $55,146) of construction in process. Amortization expense of facilities under capital lease was $2,489 (2007 - $2,583). In addition $10,458 (2007 - $2,009) of contributions received in aid of construction have been credited to facilities cost. Equipment includes cost of $3,798 (2007 - $3,946) and accumulated amortization of $1,555 (2007 - $1,314) related to equipment under capital lease. Amortization expense of equipment under capital lease was $241 (2007 - $175). In 2008, interest of $785 (2007 - $997) was capitalized to facilities within property, plant and equipment.

The Fund entered into an agreement to sell steam from the Peel Energy-from-Waste facility to an industrial customer located in close proximity to the Peel Energy-from-Waste facility and has incurred capital costs to construct additional steam generation and transmission assets to effect such sales. The Fund completed the Brampton Co-generation steam sales project ("BCI") in the second quarter of 2008. The Fund has incurred amounts totaling $14,895 (2007 - $10,196) included in facilities of which $nil is capitalized interest (2007 - $353). APMI is entitled to 50% of the cash flow above a 15% return on investment pursuant to its project management contract (see note 16).

The Fund substantially completed a major capital project to re-power its co-generation facility at Sanger, California in the fourth quarter of 2007. Included in the cost to complete the project is a development supervision fee and a performance fee to APMI for its construction management of the project (see note 16).

## 7. Intangible assets

Intangible assets consist of the following:

**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 |

**2007**

| | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Power purchase contracts | $ 120,226 | $ 37,948 | $ 82,278 |
| Customer relationships | 18,696 | 1,501 | 17,195 |
| Licenses and agreements | 696 | 640 | 56 |
| | $ 139,618 | $ 40,089 | $ 99,529 |

## 8. Derivative Assets / Liabilities

The Company uses derivative financial instruments to manage exposures to fluctuations in exchange rates and interest rates (see note 25 - 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. The Fund has effectively fixed its interest expense on this portion of the facility at a rate of 2.96% in 2008, 3.24% in 2009 and 4.18% in 2010. The Fund has not designated the swap as a hedge for accounting purposes. The fair value of the interest swap at December 31, 2008 was a liability of $5,531 (2007 - $nil). In 2005, AirSource entered into a fixed for floating interest rate swap until September 2015 in the notional amount of $73,300 in order to reduce the interest rate variability on its senior debt facility. AirSource has effectively fixed its interest expense on its senior debt facility at 5.47%. At the time of the acquisition of AirSource the swap had a fair value of $2,719 which has been included in the purchase price allocation. The Fund has not designated the swap as a hedge for accounting purposes. The fair value of the interest swap at December 31, 2008 was a liability of $11,288 (2007 - $134).

The Fund has entered into foreign exchange contracts to manage its exposure to the U.S. dollar as significant cash flows are generated in the U.S. The Fund 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, 2008 amounted to U.S. $115,534 until 2013 at a weighted average exchange rate of $1.06. The fair value of the outstanding forward exchange contracts is a liability of $16,735 at December 31, 2008 (2007 – asset of $11,911).

The current portion of derivative assets is $nil (2007 – $7,857). The current portion of derivative liabilities is $8,438 (2007 - $nil)

**8. Derivative Assets / Liabilities (continued)**

The foreign exchange contracts settle according to the following table:

| | Amount | Average exchange rate |
|---|---|---|
| 2009 | US $ 32,679 | $ 1.13 |
| 2010 | 33,165 | 1.04 |
| 2011 | 29,660 | 1.03 |
| 2012 | 16,640 | 1.05 |
| 2013 | 3,390 | 1.11 |
| | US $ 115,534 | $ 1.06 |

**9. Revolving credit facility**

On January 16, 2008 the Fund renewed its combined $175,000 senior secured revolving operating and acquisition credit facilities (the "Facilities") for a new three year term with its Canadian bank syndicate. Under terms of the renewal, the Facilities are extended for a three year term with a maturity date of January 14, 2011. The renewed Facilities also contain an accordion feature allowing the Facilities to increase to $225,000 to accommodate future growth and acquisitions. During 2008, the Company exercised $17,750 of the accordion feature bringing the Fund's available credit under the revolving credit facility with its senior lenders to $192,750. At December 31, 2008, Algonquin had $18,250 of committed and available bank facilities. In addition, subject to the covenants included in the Facilities, $8,800 of the unexercised accordion feature would, if exercised, be available to be drawn as at December 31, 2008.

At December 31, 2008, $137,000 (2007 - $126,000) (see note 10 – Long-term liabilities) 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 $37,508 (2007 - $24,986).

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

## 10. Long-term liabilities

Long term liabilities consist of the following:

| | 2008 | 2007 |
|---|---|---|
| Revolving credit facility (Note 9):<br>Revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus 0.95%. The effective rate of interest for 2008 was 4.25% (2007 - 5.77%). | $ 137,000 | $ 126,000 |
| AirSource Senior Debt Financing:<br>Interest rate is equal to bankers' acceptance plus 1% and matures on October 31, 2011. Interest payments only until April 2008 and quarterly interest and principal payments of $1,368 made commencing June 2008. The effective rate of interest for 2008 was 4.55% (2007 - 5.50%). | 71,865 | 73,207 |
| Senior Debt Long Sault Rapids:<br>Interest at rate of 10.2% repayable in monthly installments of $402 which commenced in February 1999 and maturing December, 2027. | 41,246 | 41,835 |
| Sanger Bonds:<br>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 2008 is 2.16% (2007 - 3.65%). | 23,512 | 18,972 |
| Litchfield Park Service Company Bonds:<br>1999 and 2001 IDA Bonds. Interest rates of 5.87% and 6.71% repayable in semi-annual installments, maturing October 2023 and October 2031. The balance of these notes at December 31, 2008 was U.S. $4,527 and U.S. $8,077, respectively (2007 – U.S. $4,720 and U.S. $8,171). | 15,436 | 12,738 |
| Senior Debt Chute Ford:<br>Interest rate of 11.6% repayable in monthly installments of $64 which commenced in February 1996 and maturing April, 2020. | 4,795 | 4,991 |
| Bella Vista Water Loans:<br>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, 2008 was US$1,650 and US$111 respectively (2007 - US$1,650 and US$119). | 2,125 | 1,748 |
| Bonds Payable:<br>Obligation to the City of Sanger due October 1, 2011 at interest rates varying from 5.15% to 5.55%. U.S. $650 (2007 - U.S. $845). | 796 | 835 |

## 10. Long term liabilities (continued)

| | 2008 | 2007 |
|---|---|---|
| AirSource Development Debt: Financing from Highground Capital Corporation Inc. which bears interest at 11.25% per annum. Prior to December 31, 2008, payments in respect of development debt financing consisted of interest only. Upon acquisition of Highground from CJIG this debt was eliminated. See note 3(a). | - | 1,600 |
| AirSource Participation Agreement: Financing from Highground Capital Corporation Inc. which bears interest at 9.25% per annum. Upon acquisition of Highground from CJIG this debt was eliminated. See note 3(a). | - | 1,400 |
| Other | 50 | 127 |
| | $ 296,826 | $ 283,453 |
| Less: current portion | (3,235) | (1,728) |
| | $ 293,590 | $ 281,725 |

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 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 to the Fund from specific facilities. As at December 31, 2008 the Fund and its subsidiaries were in compliance with all debt covenants.

Interest paid on the long-term liabilities was $16,189 (2007 - $15,748).

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

| | |
|---|---|
| 2009 | $ 3,235 |
| 2010 | 3,438 |
| 2011 | 207,599 |
| 2012 | 1,626 |
| 2013 | 1,782 |
| Thereafter | 79,146 |
| | $ 296,826 |

## 11. Convertible Debentures

In 2006, the Fund issued 60,000 of convertible unsecured subordinated debentures at a price of $1 per debenture for gross proceeds of $60,000 and net proceeds of $57,100. The debentures are recorded on the financial statements net of issue costs of $2,900, resulting in an effective interest rate of 7.05%. The debentures are due November 30, 2016 and bear interest at 6.20% per annum, payable semi-annually in arrears on May 31 and November 30 each year. The convertible debentures are 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 90.9091 trust units per $1 principal amount of debentures. The debentures may not be redeemed by the Fund prior to November 30, 2010. During the period of November 30, 2010 until November 29, 2012, the debentures may be redeemed by the Fund if the underlying trust unit price is equal to or exceeds a price of $13.75 (125% of the conversion price of $11.00). During the period of November 30, 2012 until the debenture’s maturity, the Fund 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 trust units. The Fund performed an evaluation of the embedded holder option and determined that its value was $479 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 debt accretion expense on the Consolidated Statements of Operations.

In 2004, the Fund issued 85,000 of convertible unsecured subordinated debentures at a price of $1 per debenture for gross proceeds of $85,000 and net proceeds of $81,105. The debentures are recorded on the financial statements net of issue costs of $3,895, resulting in an effective interest rate of 7.55%. The debentures are due July 31, 2011 and bear interest at 6.65% per annum, payable semi-annually in arrears on January 31 and July 31 each year. The convertible debentures are 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 93.8967 trust units per $1 principal amount of debentures. The debentures can be redeemed by the Fund subsequent to July 31, 2007. During 2008, the Fund did not redeem any debentures.

During the period of July 31, 2007 until July 30, 2009, the debentures may be redeemed by the Fund if the underlying trust unit price is equal to or exceeds a price of $13.31 (125% of the conversion price of $10.65). During the period of July 31, 2009 until the debenture’s maturity, the Fund 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 trust units. The Fund performed an evaluation of the embedded holder option and determined that its value was nominal and as a result the entire amount of the debentures are classified as a liability.

During 2008, nil (2007 - 16) of 2004 convertible debentures were converted into nil (2007 - 1,502) units which resulted in an increase in units of $nil (2007 - $16) and a decrease in convertible debentures by a similar amount.

Total interest paid on the convertible debentures in 2008 was $9,370 (2007 - $9,448).

## 12. Other long-term liabilities

Other long term liabilities consist of the following:

| | 2008 | 2007 |
|---|---|---|
| Capital Leases<br>Obligation for equipment leases. Interest rates varying from 5.75% to 12.25%, monthly interest and principal payments with varying dates of maturity from March 2008 to October 2024 | $ 375 | $ 2,504 |
| Advances in aid of construction | 17,500 | 10,789 |
| Customer Deposits | 3,020 | 2,622 |
| Deferred water rights | 3,170 | 3,252 |
| Other | 5,795 | 4,791 |
| | 29,860 | 23,958 |
| Less: current portion | (1,001) | (187) |
| | $ 28,859 | $ 23,771 |

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

| | |
|---|---|
| 2009 | $1,001 |
| 2010 | 125 |
| 2011 | 52 |
| 2012 | 42 |
| 2013 | - |
| Thereafter | 28,640 |
| | $ 29,860 |

Interest paid on other long-term liabilities was $52 (2007 - $46).

## 13. Trust units

### Authorized trust units

The 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.

Trust Units consist of the following:

| | 2008 | 2007 |
|---|---|---|
| Balance of Trust units, beginning of period | $ 691,734 | $ 684,414 |
| Issued on conversion of Algonquin (AirSource) Power LP exchangeable units | 4,016 | 7,304 |
| Conversion of convertible debentures | - | 16 |
| Issued pursuant to Highground transaction (Note 3 (a)) | 26,203 | - |
| Balance of Trust Units, end of period | $ 721,953 | $ 691,734 |
| Trustee Loans (note 16) | (217) | - |
| Equity component of convertible debentures (note 11) | 479 | 479 |
| Trust Units | $ 722,215 | $ 692,213 |

Number of trust units:

| | 2008 | 2007 |
|---|---|---|
| Trust units, beginning of period | 73,644,356 | 72,874,211 |
| Issued on conversion of Algonquin (AirSource) Power LP exchangeable units | 422,873 | 768,643 |
| Conversion of convertible debentures | - | 1,502 |
| Issued pursuant to Highground transaction (Note 3(a)) | 3,507,143 | - |
| Trust units, end of period | 77,574,372 | 73,644,356 |

Subsequent to the end of the year, the Fund issued 63,500 trust units pursuant to the conversion provisions for exchangeable units.

## 14. Income taxes

The Fund is an unincorporated trust and is subject to current income taxes on taxable income not distributed to its Unitholders. For 2008 the Fund made distributions to Unitholders of its current taxable income and plans to continue to distribute all future current taxable income to its Unitholders. Consequently, no provision for current income taxes or for future income taxes on temporary differences reversing prior to 2011 has been made in these financial statements for income of the Fund and its flow-through subsidiaries as these will be the responsibility of the Unitholders. Current and future income taxes have been provided in respect of taxable income and temporary differences related to the corporate subsidiaries of the Fund.

The provision for income taxes in the consolidated statements of earnings represents an effective tax rate different than the Canadian enacted statutory rate of 33.05% (2007 - 32.05%). The differences are as follows:

| | 2008 | 2007 |
|---|---|---|
| Expected income tax expense / (recovery) at Canadian statutory rate | (7,228) | 12,650 |
| Increase (decrease) resulting from: | | |
| Accounting losses (income) of the Fund to be taxed at the unitholder level | 4,513 | (12,122) |
| Differences in tax rates in subsidiaries and changes in tax law and rates | 426 | 17,162 |
| Change in valuation allowances | 21,239 | 10,041 |
| Foreign exchange loss on intercompany items | (18,329) | (12,600) |
| Other | (313) | (23) |
| Income tax expense | $ 308 | $ 15,108 |

## 14. Income taxes (continued)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis that give rise to significant portions of the future tax assets and future tax liabilities at December 31, 2008 and 2007 are presented below:

| | 2008 | 2007 |
|---|---|---|
| Future tax assets: | | |
| Non-capital loss, debt restructuring charges and currently non-deductible interest carry forwards | $ 25,355 | $ 19,561 |
| Unrealized foreign exchange differences on US entity debt | 11,674 | 30,003 |
| Customer advances in aid of construction | 6,768 | 4,414 |
| Foreign exchange hedges and interest rate swaps | 3,940 | - |
| Total future tax assets | 47,737 | 53,978 |
| Less: Valuation allowance | (24,705) | (42,996) |
| Total future tax assets | 23,032 | 10,982 |
| Future tax liabilities: | | |
| Property, plant and equipment | (95,007) | (81,567) |
| Intangible assets | (9,861) | (8,174) |
| Other | (2,115) | (366) |
| Total future tax liabilities | (106,983) | (90,107) |
| Net future tax liability | $ (83,951) | $ (79,125) |

Classified in the financial statements as:

| | 2008 | 2007 |
|---|---|---|
| Future non-current income tax asset | $ 2,894 | $ 2,416 |
| Future current income tax liability | (1,191) | (756) |
| Future non-current income tax liability | (85,654) | (80,785) |
| | $ (83,951) | $ (79,125) |

Current income tax recoverable of $1,538 (2007 - $nil) is included as part of accounts receivable on the financial statements.

On June 22, 2007 legislation ("the SIFT Rules") relating to the federal income taxation of publicly-traded trusts and partnerships received royal assent. Under transitional relief the SIFT Rules will not apply to a publicly-traded trust or partnership that is a "specified investment flow through entity" (a "SIFT") which was listed before November 1, 2006 ("Existing Trust") until taxation years ending in or after 2011. The SIFT Rules do not affect the current and future tax amounts of the Fund's corporate subsidiaries.

Under the SIFT Rules, distributions of certain income by a SIFT will not be deductible in computing the SIFT's taxable income, and the SIFT will be subject to tax on such income at a rate that is substantially equivalent to the general tax rate applicable to Canadian corporations. A SIFT's income that is dividends or income received directly from foreign sources will continue to be taxed to unitholders under the existing rules and distributions paid by a SIFT as returns of capital will not be subject to this tax. An Existing Trust may lose its transitional relief where its equity capital grows beyond certain dollar limits measured by reference to the Existing Trust's market capitalization at the close of trading on October 31, 2006 in which case application of this tax to an Existing Trust may commence before 2011.

## 14. Income taxes (continued)

The Fund is a SIFT as defined in the SIFT Rules. Accordingly commencing January 1, 2011 the Fund will be subject to taxes on certain income earned from investments in its subsidiaries. The tax payable by the Fund on that income will result in a corresponding decrease to the cash flow available to be distributed to the Unitholders. The Fund has recognized future income tax assets and liabilities with respect to the temporary differences of its assets and liabilities and those of its flow-through subsidiaries that are expected to reverse in or after 2011. The Fund expects that its income will not be subject to tax prior to 2011 and accordingly has not provided future income taxes on its temporary differences and those of its flow through subsidiaries that are expected to reverse before 2011.

Under the SIFT Rules, flow-through subsidiaries of the Fund may also themselves be SIFTs although the intent and interpretation of the legislation is not entirely clear. The Fund has concluded that even if it is determined that these flow-through subsidiaries meet the definition of a SIFT, there should be no material impact on the income tax provision and future tax assets and liabilities of the Fund. On December 20, 2007, the Minister of Finance announced his intention to introduce technical amendments to the SIFT definition to exclude certain flow-through subsidiaries of a SIFT that are able to meet certain ownership conditions. Draft legislation in respect of these technical amendments is included in Bill C-10 which received first reading on February 6, 2009, but as yet has not been enacted. Under such technical amendments, if enacted in their current form announced, the majority of the Fund's flow-through subsidiaries would not themselves be SIFTs.

The Fund and its flow-through subsidiaries have assets and liabilities with a net aggregate tax basis exceeding accounting basis by $12,544 (2007 - $(22,452)) which are not included in future tax assets and liabilities reported above.

The Fund's subsidiaries have $59,369 of tax losses that are expiring between 2009 and 2028.

## 15. Loss/(gain) on derivative financial instruments

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

| | 2008 | 2007 |
|---|---|---|
| Unrealized loss/(gain) on derivative financial instruments: | | |
| Foreign exchange contracts | $ 25,473 | $ (6,950) |
| Interest swaps | 16,953 | 2,088 |
| Total unrealized loss/(gain) on derivative financial instruments | $ 42,426 | $ (4,862) |
| Realized loss/(gain) on derivative financial instruments: | | |
| Foreign exchange contracts | $ (5,077) | $ (9,540) |
| Interest rate swaps | 399 | (67) |
| Total realized loss/(gain) on derivative financial instruments | $ (4,678) | $ (9,607) |
| Loss/(gain) on derivative financial instruments | $ 37,748 | $ (14,469) |

## 16. Related party transactions

In addition to the transaction described in note 3 (a) with APMI, the following related party transactions occurred:

APMI provides management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. In 2008 and 2007, APMI was paid on a cost recovery basis for all costs incurred and charged $893 (2007 - $867). APMI is 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 2008 $nil (2007 - $770) 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 2008, APMI was paid $23 (2007 - $98) 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.

The Fund 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 2008 were $296 (2007 - $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 are subject to promissory notes issued in favour of the Company which are repayable upon demand, currently bear interest at 3% per annum, and are recorded as a reduction in Trust Units on the consolidated balance sheet. During 2008 a principal repayment of $8 was made. (2007 - $nil) (note 13)

The Fund utilizes chartered aircrafts, 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 the Fund's business use of the aircraft. Under the terms of this arrangement, the Fund 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; such direct operating costs do not provide the affiliate with any profit or return on or of the capital committed to the aircraft. During the year, the Fund incurred costs in connection with the use of the aircraft of $332 (2007 - $422) and amortization expense related to the advance against expense reimbursements of $90 (2007 - $168). At December 31, 2008, the remaining amount of the advance was $818 (2007 - $908).

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 3 (a) and note 10).

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 GWAP, a company controlled by APMI, was paid a final payment of $134 (2007 - $845) in 2008 for construction services. In 2008, the Fund also paid $nil (2007 - $1,353) to GWAP on a cost recovery basis related to ongoing operating expenses of the project.

**16. Related party transactions (continued)**

Pursuant to the St. Leon Limited Partnership Agreement, in 2006, St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of Airsource and the legal owner of the St. Leon facility, was required to issue 100 Class B units to GWAP. 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 after June 17, 2008, two years after the date the facility achieved commercial operations pursuant to the PPA. Such income allocations and cash distributions shall be increased by 2.5% for each successive 5 year period, to a maximum of 10.0%. 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 holders of the Class B units are entitled to cash distributions of $288 for the year ended December 31, 2008 (2007 - $nil).

AirSource has agreed to reimburse AirSource Power Fund GP Inc (the "General Partner") of the AirSource Power Fund I LP for reasonable costs incurred by it in acting as registrar and transfer agent and in attending to the administration of the Partnership, as required in the Partnership Agreement. The general partner was paid $nil during the year ended December 31, 2008 (2007 - $11).

Pursuant to the agreement entered into on June 27, 2008 between the Company, Highground and CJIG (Note 3(a)), APMI is entitled to a fee of approximately $240 from the Company. This fee has been accrued and included in accounts payable on the consolidated balance sheet and is included in transaction costs of trust units issued.

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 2008, no amounts were paid under this agreement. However, APMI earned a construction supervision fee of $100 in relation to the development of this project.

## 17. Discontinued Operations

During 2007, the Fund disposed of certain landfill gas and hydroelectric facilities that were no longer considered strategic to the ongoing operations of the Fund for gross proceeds of $14,083. The result of operations from these facilities are disclosed as net earnings/(loss) from discontinued operations on the consolidated statement of earnings as discontinued operations.

The results of the discontinued operations which have been included in the consolidated statement of earnings were as follows:

| | 2008 | 2007 |
|---|---|---|
| Revenue | $ - | $ 6,651 |
| Expenses | - | 8,077 |
| Operating loss | - | (1,426) |
| Interest expense | - | 72 |
| Amortization of capital and intangible assets | - | 1,192 |
| Current income tax expense | - | 1,336 |
| Future income tax recovery | - | (342) |
| Gain on sale of Property, plant and equipment and intangible assets | - | (2,592) |
| Net earnings/(loss) from discontinued operations | - | (1,092) |
| Add: | | |
| Amortization of capital and intangible assets | - | 1,192 |
| Less: | | |
| Future income tax recovery | - | (342) |
| Gain on sale of Property, plant and equipment and intangible assets | - | (2,592) |
| Net cashflow from discontinued operations | $ - | $ (2,834) |

Assets held for sale consist of the following:

| | | |
|---|---|---|
| Property, plant and equipment | $ - | $ - |
| Intangible assets | - | - |
| | $ - | $ - |

## 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. The Fund incurred $3,181 during 2008 (2007 - $2,493) in respect of these agreements for all of its operating entities.

(b) Contingencies

The Fund 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 the Fund'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. The Fund is in the process of conducting the assessments as required. Based on assessments to date, some of which are preliminary, the Fund has estimated potential remedial measures involving capital expenditures of approximately $14,465 which may be required to comply with the legislation. The Fund is currently exploring several alternatives to reduce or mitigate these potential capital expenditures, including technical alternatives and cost sharing with other stakeholders. Accordingly, it is not determinable at this time the amount of remedial capital expenditures that might ultimately have to be borne by the Fund, nor the number of years within which these capital expenditures may need to be completed.

(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 $4,635.

## 19. Fair Value of Financial instruments and Derivatives

The carrying amount of the Fund's cash, accounts receivable, restricted cash, accounts payable and accrued liabilities, due to Algonquin Power Group and distributions payable, approximate fair market value.

The carrying amount of the Fund's long-term investments is dependant on the underlying operations and accordingly a fair value is not readily available. The Fund has long-term liabilities and convertible debentures at fixed interest rates or variable rates. The estimated fair value of these long-term liabilities at current rates would be $373,822 (2007 - $286,445). The book value of these long-term liabilities is $434,018 (2007 - $283,452). 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 (g)) 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.

## 20. Cash distributions

All cash distributions of the Company are made on a discretionary basis as determined by the Trustees of the Company. In 2008, the Company paid monthly cash distributions of $0.0766 per unit from January to September and $0.02 per unit from October to December. For the year ended December 31, 2008, the Company paid cash distributions to unitholders totaling $56,046 (2007 - $67,416) or $0.75 per unit (2007 - $0.92).

Total distributions to the unitholders of the Algonquin (Airsource) Power LP exchangeable units for 2008 were $1,709 (2007 - $2,516) which have been recorded as a reduction in non controlling interest on the consolidated Balance Sheet.

## 21. Basic and diluted net earnings per trust unit

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

| | **2008** | **2007** |
|---|---|---|
| Weighted average trust units – basic | 75,265,940 | 73,423,639 |
| Trust units issuable on conversion of exchangeable units | 2,042,103 | 2,703,593 |
| Weighted average trust units – diluted | 77,308,043 | 76,127,232 |

Trust units issuable on conversion of exchangeable units are calculated based on the weighted average exchangeable units outstanding during the year at the year end exchange rate.

## 22. Interest, dividend and other income

Other income includes the following items:

| | 2008 | 2007 |
|---|---|---|
| Interest income | $ 918 | $ 2,379 |
| Dividend income | 2,928 | 3,222 |
| Termination fee | - | 1,750 |
| Equity income | 373 | 390 |
| Gain on sale of Brooklyn note | 918 | - |
| Gain on sale of land rights | 700 | - |
| Other | 1,186 | 1,667 |
| | $ 7,023 | $ 9,408 |

During 2007, the Fund allowed its offer to acquire all the outstanding trust units and convertible debentures of the Clean Power Income Fund ("CPIF") to expire. In connection with the expiry of the offer, a termination fee of $1,750 was paid to the Fund. The Fund was reimbursed $850 from CPIF for its expenses.

## 23. Other revenue

Other revenue consists of the following:

| | 2008 | 2007 |
|---|---|---|
| St. Leon wind energy facility liquidated damages | $ - | $ 17,123 |
| Natural gas sales | 481 | 1,405 |
| Hydro mulch sales | 3,832 | 3,774 |
| Other | 36 | - |
| | $ 4,349 | $ 22,302 |

## 24. Segmented Information

In January 2008, the Company realigned its operations into two business units – Power Generation & Development, and Utilities Services. The results for the year ended December 31, 2008 have been classified to reflect this new segmented reporting and comparative figures have been reclassified to also reflect new segmented reporting. Geographic segments remain unchanged.

The Company identified two business categories it operates in: Power Generation & Development, and Utility Services. The Power Generation & Development business unit develops and operates a portfolio of electrical energy generation facilities. Within this business unit 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.

The Utility Services business unit provides transportation and delivery of water and wastewater in its service areas.

## 24. Segmented Information (continued)

### Geographic Segments

The Fund 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:

| | 2008 | 2007 |
|---|---|---|
| Revenue | | |
| Canada | $ 85,094 | $ 76,146 |
| United States | 128,702 | 110,029 |
| | $ 213,796 | $ 186,175 |
| Property, plant and equipment | | |
| Canada | $ 461,982 | $ 467,991 |
| United States | 342,983 | 292,686 |
| | $ 804,965 | $ 760,677 |
| Intangible assets | | |
| Canada | $ 52,513 | $ 56,142 |
| United States | 44,885 | 43,387 |
| | $ 97,398 | $ 99,529 |
| Other assets | | |
| Canada | $ 799 | $ 1,484 |
| United States | 2,045 | 1,253 |
| | $ 2,844 | $ 2,737 |

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

### Operational segments

The new reporting segments are Renewable Energy, Thermal Energy and Utility Services. 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 in the same manner as interest expense. The operations and assets for these segments are as follows:

## 24. Segmented Information (continued)

### Operational Segments (continued)

| Year ended December 31, 2008 | | | | | | |
|---|---|---|---|---|---|---|
| | Power Generation & Development | | | Utility Services | 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 | (16,480) | (13,269) | (29,750) | (6,791) | - | (36,541) |
| Amortization of intangible assets | (2,617) | (3,934) | (6,551) | (754) | - | (7,305) |
| Earnings / (loss) from continuing operations before income taxes, minority interest and comprehensive income | 15,142 | 12,735 | 27,877 | 8,700 | (58,449) | (21,872) |
| Loss from discontinued operations | - | - | - | - | - | - |
| Net earnings / (loss) before income taxes, minority interest and comprehensive income | 15,142 | 12,735 | 27,877 | 8,700 | (58,449) | (21,872) |
| Property, plant and equipment | $418,899 | $190,387 | $609,286 | $195,679 | $- | $804,965 |
| Intangible assets | 33,256 | 34,353 | 67,608 | 29,790 | - | 97,398 |
| Total assets | 473,554 | 265,631 | 739,185 | 233,883 | 5,062 | 978,130 |
| 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 |

## 24. Segmented Information (continued)

### Operational Segments (continued)

| Year ended December 31, 2007 | Power Generation & Development | | | Utility Services | Corporate | Total |
|---|---|---|---|---|---|---|
| | Renewable Energy | Thermal Energy | Total | | | |
| **Revenue** | | | | | | |
| Energy sales | $ 49,688 | $66,877 | $116,565 | $ - | $- | $116,565 |
| Waste disposal fees | - | 13,609 | 13,609 | - | - | 13,609 |
| Water reclamation and distribution | - | - | - | 33,699 | - | 33,699 |
| Other revenue | 17,123 | 5,179 | 22,302 | - | - | 22,302 |
| Total revenue | 66,811 | 85,665 | 152,476 | 33,699 | - | 186,175 |
| **Operating expenses** | 16,132 | 65,781 | 81,913 | 17,401 | - | 99,314 |
| | 50,679 | 19,885 | 70,563 | 16,298 | - | 86,861 |
| Other administration costs | (343) | (298) | (641) | (211) | (9,248) | (10,100) |
| Foreign exchange gain / (loss) | - | - | - | - | 7,688 | 7,688 |
| Interest expense | (9,415) | (1,322) | (10,737) | (1,011) | (14,817) | (26,565) |
| Interest, dividend and other income | 2,571 | 4,878 | 7,449 | 33 | 1,926 | 9,408 |
| Gain / (loss) on derivative financial instruments | (2,020) | 6,244 | 4,224 | 3,296 | 6,949 | 14,469 |
| Write down of note receivable | - | (726) | (726) | - | - | (726) |
| Amortization of property, plant and equipment | (16,185) | (11,230) | (27,415) | (6,863) | - | (34,278) |
| Amortization of intangible assets | (2,569) | (3,904) | (6,473) | (814) | - | (7,287) |
| Earnings / (loss) from continuing operations before income taxes, minority interest and comprehensive income | 22,718 | 13,527 | 36,244 | 10,728 | (7,502) | 39,470 |
| Loss from discontinued operations | (126) | (966) | (1,092) | - | - | (1,092) |
| Net earnings / (loss) before income taxes, minority interest and comprehensive income | 22,592 | 12,561 | 35,152 | 10,728 | (7,502) | 38,378 |
| Property, plant and equipment | $417,990 | $201,569 | $619,559 | $141,118 | $- | $760,677 |
| Intangible assets | 34,903 | 38,287 | 73,190 | 26,339 | - | 99,529 |
| Total assets | $476,177 | $282,369 | $758,546 | $174,142 | $21,379 | $954,067 |
| Capital expenditures | (5,050) | 26,210 | 21,160 | 18,097 | 314 | 39,571 |
| Acquisition of operating entities | - | - | - | 990 | - | 990 |

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2008 or 2007: Hydro Québec 14% (2007 - 16%), Pacific Gas and Electric 14% (2007 - 14%), and Connecticut Light and Power 22% (2007 - 24%). The Fund has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

## 25. Financial instruments

a) Fair Value Disclosure

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, 2008 and 2007 due to the short-term maturity of these instruments.

b) 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$2,837 is spread over approximately 69,000 customers, resulting in an average outstanding balance of less than $50 per customer. 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.

## 25. Financial instruments (continued)

As at December 31, 2008 the Company's exposure to credit risk for these financial instruments was as follows:

| | December 31, 2008 | |
|---|---|---|
| | Canadian $ | US $ |
| Cash and cash equivalents | 3,475 | 1,982 |
| Accounts receivable | 11,104 | 13,311 |
| Allowance for Doubtful Accounts | - | (218) |
| | $ 14,579 | $ 15,075 |

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, 2008, in addition to cash on hand of $5,902 the Company had $18,250 available to be drawn on its senior debt facility. In addition there is approximately $8,800 that could be exercised under the unexercised portion of accordion feature contained in these facilities. 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 | $ 296,823 | $ 3,233 | $211,037 | $ 3,407 | $ 79,146 |
| Accounts Payable | 34,073 | 34,073 | | | |
| Interest on Long term debt obligations | 132,839 | 20,146 | 39,530 | 21,522 | 51,641 |
| Derivative financial instruments: | | | | | |
| Currency Forwards | 16,735 | 3,070 | 10,917 | 2,748 | - |
| Interest Rate Swaps | 16,819 | 5,368 | 7,522 | 3,228 | 701 |
| Lease Payments | 375 | 102 | 177 | 5 | 91 |
| Other obligations | 12,171 | 260 | 515 | 515 | 10,881 |
| Total obligations | $ 509,835 | $ 66,252 | $269,698 | $ 31,425 | $ 142,460 |

*Foreign Currency Risk*

The Company's Power Generation & Development business unit conducts a significant amount of business in the U.S. generating $87,593 or approximately 52.4% of its revenue in U.S. funds from integrated foreign operations in the twelve months ended December 31, 2008. This business unit also incurred $60,839 or approximately 65.4% of operating expenses in U.S. funds from integrated foreign operations in the twelve months ended December 31, 2008. Algonquin's Utility Services business unit is considered self sustaining and has been excluded from this analysis. Accordingly, the Company was exposed to foreign exchange risk of approximately $26,754 during the twelve months ended December 31, 2008. On an unhedged basis, each 5% change in the value of the U.S. dollar against the Canadian dollar would have a $1,338 impact on earnings from operations.

## 25. Financial instruments (continued)

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. Algonquin 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, 2008, the exercise of these forward contracts will result in the use of $3,070 in cash in fiscal 2009, the use of $5,668 in fiscal 2010 and result in the use of $7,997 in cash for the remainder of the hedged period beyond 2010. Assuming a decrease in the strength of the US dollar relative to the Canadian dollar of $0.05 at December 31, 2008 with a corresponding change in the forward yield curve, the fair value of the outstanding forward exchange contracts would increase by $5,777, increasing the expected cash generated during fiscal 2009 by $1,634, $1,658 in fiscal 2010 and $2,485 for the remainder of the hedged period beyond 2010.

As at December 31, 2008, Algonquin had US$115,534 in outstanding foreign exchange forward contracts with an average rate of $1.064 and having a fair value liability of $16,735.

The Company has performed sensitivity analysis on its U.S. dollar denominated financial instruments which consist principally of cash US$1,982 and net negative U.S. dollar working capital of $4,402 at December 31, 2008, to determine how a change in the U.S. dollar exchange rate would impact net earnings. As at December 31, 2008, 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 $121 change in the Company's net earnings for the twelve months ended December 31, 2008.

*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, 2008 to determine how a change in interest rates would impact equity and net earnings:

- The Company’s senior debt facility has a balance of $137,000 as at December 31, 2008. Assuming the current level of borrowings, a 1% change in the variable rate charged would impact interest expense by $1,370 during the twelve months ended December 31, 2008. 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, 2008, the fair value of the interest rate swap was a net $5,531 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.

## 25. Financial instruments (continued)

- The Company's project debt at the St. Leon facility has a balance of $72,121 as at December 31, 2008. Assuming the current level of borrowings, a 1% change in the variable rate charged would have impacted interest expense by $721 during the twelve months ended December 31, 2008. At December 31, 2008, the fair value of the interest rate swap was a net $11,288 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, 2008. 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, 2008. This analysis assumes that all other variables, in particular foreign currency rates, remain constant.

As of December 31, 2008, the derivative liabilities are as follows:

| | | |
|---|---|---|
| Derivative liabilities: | | |
| Fair Market Value of Interest Rate SWAP – St Leon | $ | (11,288) |
| Net Fair Market Value of Interest Rate SWAP – revolving credit facility | | (5,531) |
| Net Fair Market Value of long term portion of Foreign Exchange Hedges | | (16,735) |
| **Total derivative liabilities** | **$** | **(33,554)** |

## 26. 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 distributions made to Unitholders.
- 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 that it remains appropriate for its respective business units.

## 27. Comparative figures

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

# Corporate Information

## Trustees



## The Management Group

**Algonquin Power Management Inc.**
**Chris Jarratt,** Chief Executive Officer and Director
**David Kerr,** Director
**Ian Robertson,** Director

## Algonquin Power Income Fund

**David Bronicheski,** Chief Financial Officer

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Toronto, Ontario

## Stock Exchange

The Toronto Stock Exchange: APF.UN, APF.DB, APF.DB.A

## Legal Counsel

Blake, Cassels & Grayson LLP

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