INVEST IN POWER

ATLANTIC POWER CORPORATION **ANNUAL REPORT 2006**

AtlanticPower Corporation

2006

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CORPORATE PROFILE

Atlantic Power Corporation owns interests in a diversified and growing portfolio of power generating and transmission projects located primarily in major markets in the United States. The Company's objectives are to sustain and grow its cash distributions over the long term by enhancing the performance of its existing assets and by making accretive acquisitions. The Company's Income Participating Securities (IPSs) are listed on the Toronto Stock Exchange under the symbol ATP.UN.

FINANCIAL HIGHLIGHTS

(US$000 except where noted and per IPS data)

Year ended December 31	**2006**	2005
Project revenue	**242,858**	184,700
Project income	**57,247**	48,256
Total assets	**1,176,275**	926,630
Cash available for distribution (Cdn$000)	**67,399**	58,981
Cash available for distribution per basic IPS (Cdn$)	**1.45**	1.46
Total IPS distributions (Cdn$000)	**49,151**	39,124
Total distribution per basic IPS (Cdn$)	**1.04**	1.01
Market capitalization at December 31 (Cdn$000)	**694,002**	461,131

MEETING OUR GOALS

In 2006 we made considerable progress on all of our key objectives:

1. **Sustain and grow cash flows:**
   - Project EBITDA up 17%
   - Annual cash distributions per IPS increased 3%

2. **Make accretive acquisitions:**
   - Purchase of Path 15 transmission line enhances portfolio diversity, reduces risk, and strengthens stability and duration of cash flow

3. **Enhance financial flexibility:**
   - Cdn$150 million public financing in October which included:
     - Cdn$90 million of IPSs and
   - Cdn$60 million convertible debentures
   - Continue to use project-level financing with no recourse to Atlantic Power

4. **Generate strong returns for investors:**
   - 38% total return for investors from our IPO in November 2004 through December 31, 2006

SOLID GROWTH IN CASH FLOW

REPORT TO SHAREHOLDERS

We continued to execute our strategy of making accretive acquisitions and enhancements at existing projects to grow shareholder value.

Executing our strategy

2006 was another solid year for Atlantic Power as we strengthened and further diversified our portfolio of power generation and transmission assets while growing EBITDA and cash available for distribution. Based on the projected performance of the portfolio and the completion of a key accretive acquisition during the year, we were pleased to increase annual cash distributions to investors by Cdn$0.03 per IPS, the second increase since we entered the public capital markets in November 2004. We are also pleased that our IPS investors have enjoyed a total return, including distributions and price appreciation, of 38% since our IPO.

For the year ended December 31, 2006, cash available for distribution was $57.9 million, an increase of 19% from the prior year. Distributions declared during 2006 were $43.4 million or Cdn$1.04 per IPS, generating a conservative payout ratio of 75%.

Accretive acquisition diversifies portfolio

Our first strategy for increasing distributable cash is to acquire projects that enhance the diversification of our portfolio while increasing cash available for distribution. During the third quarter of 2006 we completed the acquisition of the Path 15 transmission project, a purchase that strengthens the stability and duration of our cash flows, and enhances the diversity and risk profile of our portfolio.

Path 15 is an 84-mile, 500-kilovolt transmission line built along an existing transmission corridor in California. The line was constructed to help alleviate what had been a chronic north-south transmission congestion problem in the Western U.S. power grid. Path 15 commenced commercial operations in December 2004.

The acquisition brings a number of benefits to Atlantic Power. Path 15 is a strategic and critical transmission asset with strong federal and state support, and substantial ratepayer benefits. It will provide highly stable cash flows for nearly 30 years, and its federally regulated revenue stream is independent of market power prices or line utilization. In addition, the Path 15 project has virtually no operating risk, uses proven technology, has a solid operating history and will require minimal ongoing capital expenditures. Most importantly, the Path 15 investment was immediately accretive to our cash flow available for distribution.

Enhancements at existing projects

Another key growth initiative is to enhance the operating and financial performance of our facilities through ongoing operational improvements and the optimization of our power purchase agreements ("PPAs"), fuel supply contracts and other commercial arrangements. During the year, we upgraded the gas turbines at our Pasco project, resulting in improved efficiency and increased output. A new three-year agreement at our Rumford project will provide fixed cash flows independent of plant operations and commodity price movements. Efforts are well underway at other projects with upcoming PPA expirations to enter into agreements that maximize future cash flows. At our Gregory facility, a gas price hedge strategy was executed in late 2005 that locked in higher margins throughout 2006. Similar arrangements will continue to stabilize strong margins in 2007.

Aggregate power generation increased 12% in 2006 compared to the prior year, primarily driven by the full-year contribution from the Chambers project, acquired in September 2005 and increased output at Orlando due to last year's turbine upgrade.

STRATEGIC ACQUISITIONS

Financial flexibility expands our investor base
To finance our growth in 2006, we completed two significant transactions in the fourth quarter, which raised nearly Cdn$240 million in new debt and equity: a public offering in October consisting of Cdn$90 million of IPSs and Cdn$60 million of convertible debentures, and a Cdn$89 million private placement in December comprised of Cdn$86 million of IPSs and Cdn$3 million in separate subordinated notes. With these transactions and through IPS price appreciation, our market capitalization has increased by more than Cdn$300 million since our IPO, to approximately Cdn$685 million as at December 31, 2006, enhancing our trading liquidity.

The proceeds of the debt and equity offerings in 2006 were used to redeem all of the remaining ownership interests in Atlantic Holdings held by two private equity funds managed by ArcLight Capital and to partially repay credit facilities arranged in connection with the Path 15 acquisition. At the time of Atlantic Power's IPO, these ArcLight funds and another investor were granted the right to request that their original 41.9% interest in Atlantic Holdings be redeemed, subject to certain limitations, during the first two years after our IPO. As a result of our financings in 2006, Atlantic Holdings is now a wholly-owned subsidiary of Atlantic Power. The ArcLight funds will continue to indirectly own Atlantic Power Management, LLC, the Manager of the Company. The Manager's incentive fee, based on increasing distributions to investors, gives ArcLight a continuing motivation to contribute to our ongoing growth.

These transactions demonstrate our flexibility in accessing a range of alternatives to finance our growth. In addition to project-level debt with no recourse to Atlantic Power, at the corporate level we can access the equity and debt markets through both public and private financings, an important advantage as we drive for continued growth in the years ahead.

We were also pleased with the growing support of long-term institutional investors as the Caisse de dépôt et placement du Québec ("CDP") and other institutional investors increased their ownership in Atlantic Power. CDP is our largest shareholder and now owns 19% of the Company's outstanding IPSs. Some of these investors also represent potential partners with whom we can work on acquisition opportunities.

Building value
Going forward, we will continue to execute the same strategies that have generated our solid performance over the past two years.

We continue to pursue additional acquisition opportunities within the North American power industry that will meet our investment guidelines and result in an increase in cash available for our investors. The immediate contributions to cash flow and distribution increases in connection with the purchases of Path 15 in 2006 and an interest in the Chambers project in 2005 are excellent examples of how we are creating value by adding projects that strengthen and diversify our portfolio.

Because Atlantic Power is a taxable corporation and not a trust, we do not believe that the recent changes in Canadian tax laws will negatively impact our financial performance or our ability to grow in the future.

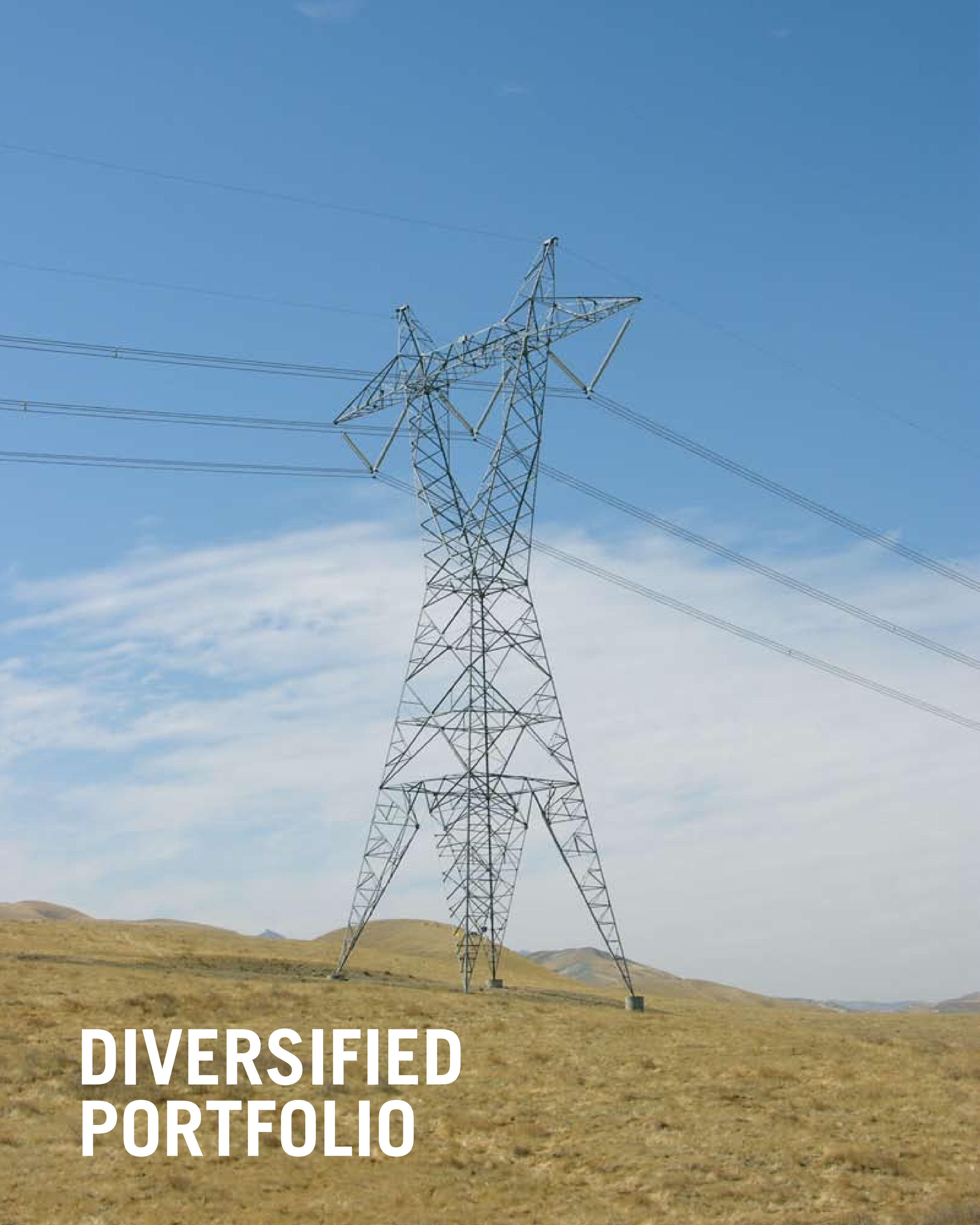
We are working with our project operators to enhance the operating and financial performance of our facilities through ongoing operational improvements, the optimization of power purchase and fuel supply agreements and other commercial arrangements.

Finally, we continue to look for opportunities to consolidate and increase our ownership in projects in which we already have partial interests.

Looking ahead, our ultimate objective remains to deliver predictable, stable and growing cash distributions for our investors. We made considerable progress in 2006, and we believe that, building on the strong foundation of our existing portfolio, we have the industry relationships and the management expertise to prudently grow the Company and continue the strong track record of performance demonstrated since our IPO.

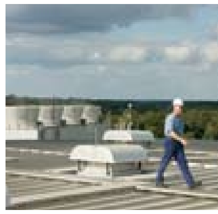
In closing, I would like to thank our employees, customers, partners and sponsors for their significant contributions, and our shareholders for their continued support.

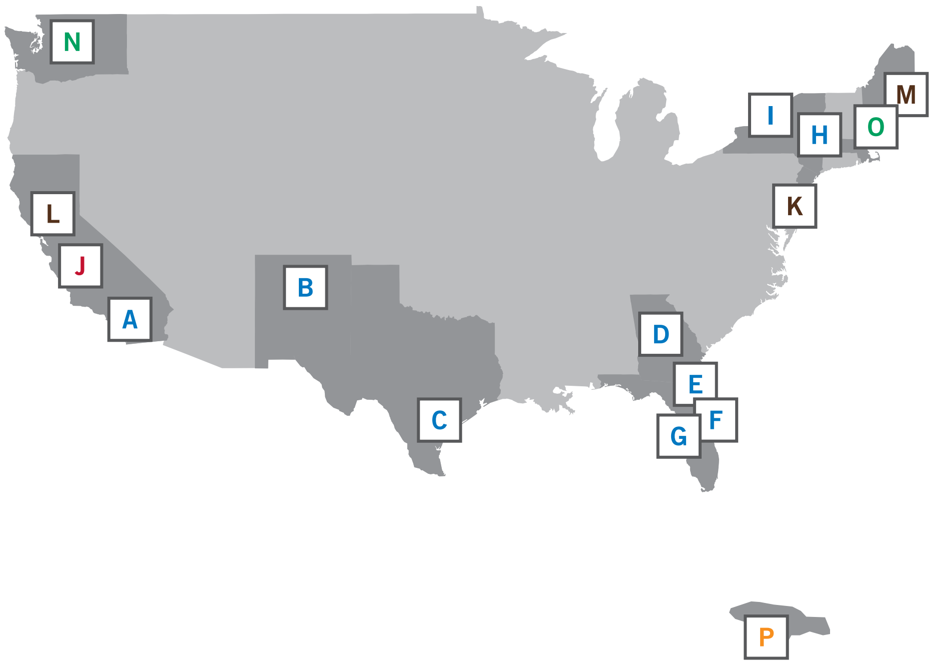
Barry Welch
PRESIDENT AND CEO



DIVERSIFIED PORTFOLIO

PROJECTS





GAS

A **Badger Creek** Bakersfield CA
B **Delta-Person** Albuquerque NM
C **Gregory** Corpus Christi TX
D **Mid-Georgia** Kathleen GA
E **Lake** Umatilla FL
F **Orlando** Orlando FL
G **Pasco** Dade City FL
H **Selkirk** Bethlehem NY
I **Onondaga** Geddes NY

TRANSMISSION LINE

J **Path 15** California

COAL

K **Chambers** Carney's Point NJ
L **Stockton** Stockton CA
M **Rumford** Rumford ME

HYDRO

N **Koma Kulshan** Whatcom County WA
O **Topsham** Topsham ME

FUEL OIL

P **JPPC** Kingston JAMAICA

BUILDING ON A STRONG TRACK RECORD

PROJECT PORTFOLIO

Project Name	Location	Fuel Type	Total MW	Ownership Interest	Net MW
Badger Creek	California	Natural Gas	46	50.00%	23
Chambers	New Jersey	Coal	262	40.00%	105
Delta-Person	New Mexico	Natural Gas	132	40.00%	53
Gregory	Texas	Natural Gas	400	17.10%	68
JPPC	Jamaica	Fuel Oil	60	24.10%	14
Koma Kulshan	Washington	Hydro	13	49.80%	6
Lake	Florida	Natural Gas	110	100.00%	110
Mid-Georgia	Georgia	Natural Gas	308	50.00%	154
Onondaga	New York	Natural Gas	91	100.00%	91
Orlando	Florida	Natural Gas	126	50.00%	63
Pasco	Florida	Natural Gas	121	49.90%	60
Path 15	California	Transmission	N/A	100.00%	N/A
Rumford	Maine	Coal/Biomass	85	23.50%	20
Selkirk	New York	Natural Gas	345	18.50%	64
Stockton	California	Coal	55	50.00%	27
Topsham	Maine	Hydro	14	50.00%	7

Additional detail in MD&A on Page 23.

MANAGEMENT DISCUSSION AND ANALYSIS

of Financial Condition and Results of Operations

The following management's discussion and analysis ("MD&A") of financial condition and results of operations should be read in conjunction with the audited financial statements of Atlantic Power Corporation ("Atlantic Power" or the "Company") for the year ended December 31, 2006. All dollar amounts in this MD&A are in thousands of U.S. dollars, unless otherwise stated. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

Forward-Looking Statements

Certain statements in this MD&A constitute forward-looking statements, which reflect the expectations of the management of Atlantic Power Management, LLC (the "Manager"), the manager of the Company regarding the Projects and the anticipated financial results and operations of the Projects (as defined below). Words such as "will", "anticipate", "expect", "project", "believe" "estimate", "forecast" and similar expressions are intended to identify forward-looking statements. Such forward-looking statements reflect current expectations regarding future events and operating performance. Forward-looking statements involve a variety of significant risks, uncertainties and assumptions pertaining to operating performance, regulatory parameters, fuel and electricity prices, weather, economic conditions and other factors that could cause actual results to differ materially from those contemplated by these statements and should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or when such performance or results will be achieved. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, the factors discussed in the "Risk Factors" section in this MD&A and under "Risk Factors" in the Company's Annual Information Form dated March 28, 2007. All forward-looking statements in this MD&A are qualified by these cautionary statements. Except as required by applicable law, the Company undertakes no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

Information contained in this MD&A is based on information available to management as of March 28, 2007.

Copies of financial data and other publicly filed documents, including the Company's annual information form, are available through the Internet on SEDAR at www.sedar.com under "Atlantic Power Corporation".

Overview

The Company currently has 61,470,500 income participating securities ("IPSs") and Cdn$60,000,000 principal amount of 6.25% convertible secured debentures due October 31, 2011 (the "Debentures") outstanding and owns 100% of the membership interest in Atlantic Power Holdings, LLC ("Holdings"). Holdings was formed initially to acquire indirect interest in a diversified portfolio of power generating facilities located primarily in major markets in the United States from ArcLight Energy Partners Funds I, L.P. ("Fund I") and ArcLight Energy Partners Funds II, L.P. ("Fund II", and, together with Fund I, the "ArcLight Funds") and Caithness Energy, LLC ("Caithness") (together with the ArcLight Funds, the "Existing Investors"). Each IPS represents: (1) one common share of the Company ("Common Share"); and (2) Cdn$5.767 aggregate principal amount of 11.0% subordinated notes of the Company ("Subordinated Notes"). The Debentures were issued on October 11, 2006 and bear interest at an annual rate of 6.25%, payable semi-annually in arrears on April 30 and October 31 of each year commencing on April 30, 2007.

As of December 31, 2006, Holdings owned interest in 14 power generating facilities in the United States and one in Jamaica, and a transmission line constructed along the Path 15 transmission corridor located in central California (collectively, the "Projects" and individually a "Project"). The generating Projects have a combined total power generating capacity of approximately 2,160 megawatts ("MW"). Holdings' interest in the Projects represented approximately 860 MW of power generating capacity as of December 31, 2006. Most of the generating Projects sell their power under long-term power purchase agreements ("PPAs") to investment-grade utilities. These agreements are typically structured to stabilize cash flows by: (1) providing a significant portion of revenues via steady capacity payments generally designed to provide a return of and on capital and to cover fixed costs regardless of how much electricity the plant is called upon to produce, provided that the plant meets an availability requirement; and (2) passing most of the generating Projects' fuel costs through to the utilities. As a result, variations in the portfolio's cash flow based on changes in the amount of power generated, spot market electricity prices and fuel price changes are significantly mitigated.

The Path 15 transmission line is a United States Federal Energy Regulatory Commission ("FERC") regulated asset with a 30-year regulatory life. Its annual revenue requirement is collected by the California Independent System Operator ("CAISO") from utilities in California without variations from the changes in power prices or line usage and with virtually no technical or operating risks.

The Company's objectives are to maintain the stability and sustainability of cash distributions to holders of IPSs in the form of interest payments on Subordinated Notes and dividends on Common Shares, and to increase, when prudent, dividends on the Common Shares. To achieve these objectives, Company management, working directly with project managers, focuses on enhancing the operation of the existing Projects by improving facility performance, increasing output and efficiency, optimizing contracts and hedging cash flows when practicable. In addition, the Company has a focused growth strategy that includes consolidating interest in Projects that it currently owns and making accretive acquisitions with a primary focus on the electric power industry in the United States and Canada.

Management believes that opportunities for accretive acquisitions will be available based on a number of factors, including continued electricity demand growth and the corresponding need for new power plants, increased liquidity in the secondary market for ownership interest in power-related assets, and superior access to potential growth transactions through ArcLight and the Manager's industry contacts. Competition for these opportunities has also increased from private equity funds and other sources.

The most significant economic factors affecting the Company's performance are changes in interest rates and the currency exchange rates between the U.S. dollar and the Canadian dollar. Most debt at the Projects bears interest at a fixed rate, but a small amount does have exposure to variability in interest rates. Substantially all of the Company's operating cash flow is earned in U.S. dollars and a large portion of the Company's cash obligations, primarily distributions on IPSs and interest payments on the Debentures, is denominated in Canadian dollars. See "Financial and Other Instruments" in this MD&A for more information about these economic risks and the Company's strategy for managing these risks.

Non-GAAP Financial Measures

Cash Flow Available for Distribution is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP. Management believes Cash Flow Available for Distribution is a relevant supplemental measure of the Company's ability to earn and distribute cash returns to investors. A reconciliation of net cash provided by operating activities from the Company's financial statements to Cash Flow Available for Distribution is set out in the "Calculation of Cash Flow Available for Distribution" section of this MD&A. Investors are cautioned that the Company may calculate this measure in a manner that is different from other companies.

Earnings before interest, taxes, depreciation and amortization ("EBITDA") is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP. Management uses aggregate unaudited EBITDA at the Projects as a supplementary cash flow measure to provide aggregate annual comparative information about Project performance. Investors are cautioned that the Company may calculate this measure in a manner that is different from other companies.

Recent Transactions

On September 15, 2006, through a subsidiary of Holdings, the Company completed the acquisition of 100% of the equity interest in Path 15 Holdco, which indirectly owns approximately 72% of the transmission system rights in a transmission line constructed along the Path 15 transmission corridor located in central California (the "Path 15" Project). The Company paid $78.4 million in cash for the equity interest in Path 15, which has approximately $145 million in non-recourse debt.

The Path 15 Project is an 84-mile, 500-kilovolt transmission line built along an existing transmission corridor in California to help alleviate what had been a chronic transmission congestion point in the state's north-south capacity. The Path 15 Project commenced commercial operations in December 2004.

The revenue stream associated with the Path 15 Project is regulated by the FERC on a cost-of-service rate base methodology, which insulates cash flows from any impacts of power prices or actual line usage. The approved rate base includes all costs that were incurred to construct and finance the transmission line by Trans-Elect NTD Path 15, LLC ("Path 15 Opco"), a wholly-owned subsidiary of Path 15 Holdco. Path 15 Opco earns an allowed rate of return on the approved rate base that is reviewed by the FERC every three years. The rate base is depreciated over 30 years. In addition, all prudently incurred operating and maintenance costs and capital expenditures may be collected in rates charged. The CAISO collects transmission access charges, which are paid predominantly by the state's investor-owned utilities, and passes them to transmission system rights owners, such as Path 15 Opco.

Subsequent to Holdings' acquisition of equity interest in Path 15 Holdco, Trans-Elect NTD Holdings Path 15, LLC was renamed Atlantic Path 15 Holdings, LLC and Trans-Elect NTD Path 15, LLC was renamed Atlantic Path 15, LLC.

The Company also announced on September 15, 2006 that it increased its cash distribution to shareholders by an annual rate of Cdn$0.03 per IPS commencing with the September distribution. Since its Initial Public Offering ("IPO") in November 2004, the Company has increased annualized cash distributions per IPS by 6%.

On October 11, 2006, the Company completed a sale of 8,531,000 IPSs and the Debentures for gross proceeds of Cdn$150 million. The IPSs were sold at a price of Cdn$10.55 per IPS for gross proceeds of Cdn$90 million and Cdn$60 million aggregate principal amount of the Debentures were issued. The IPSs and Debentures were sold on a public bought-deal basis to a syndicate of underwriters.

The Debentures pay interest semi-annually on April 30 and October 31 each year, commencing on April 30, 2007. The Debentures mature on October 31, 2011 and are convertible into approximately 80.6452 IPSs per Cdn$1,000 principal amount of Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per IPS. The Debentures are listed on the Toronto Stock Exchange under the symbol ATP.DB.

The net proceeds of the offering were used by Atlantic Power to: (1) repay US$37 million of the credit facility arranged in connection with the acquisition of an interest in the Path 15 Project; and (2) provide proceeds to Holdings that were used to redeem a portion of the ownership interest in Holdings held by the Existing Investors. In connection with the closing of the offering, Atlantic Power increased its ownership in Holdings from 70.1% to approximately 86%.

On December 20, 2006, the Company announced that it had agreed to sell, on a private placement basis, a total of 8,600,000 IPSs to three institutional investors, including Caisse de dépôt et placement du Québec ("CDP"), as well as Cdn$3.0 million principal amount of Subordinated Notes issued and sold separately from the IPSs of the Company (the "Separate Subordinated Notes"). This transaction increased CDP's ownership in the Company to 19% of IPSs outstanding. Net proceeds were used by the Company in February 2007 to acquire all of the remaining interest of the Existing Investors in Holdings.

In February 2007, the Rumford Project executed an Interim Financial Consolidation Agreement ("IFCA") with its steam host, the Rumford Paper Company ("Rumford Paper"). The IFCA consolidates the payment obligations of the various agreements between the Rumford Project and Rumford Paper into fixed payment obligations commencing January 1, 2007. The effect of the IFCA is similar to a lease wherein Rumford Paper assumes the risk of fuel and power price volatility as well as most operating costs. Payments under the IFCA will be made quarterly to the partnership over a three-year term ending December 31, 2009. The Company expects to receive annual project distributions of approximately $2.7 million during the term of the IFCA compared to project distributions in the amount of $2.3 million received in 2006 from Rumford.

Selected Financial Data (in thousands of U.S. dollars, except as otherwise stated)

(unaudited)	Three months ended December 31 2006	2005	Twelve months ended December 31 2006	2005	Period from Nov. 18, 2004 to Dec. 31, 2004
Project income					
Project revenue	**64,200**	58,023	**242,858**	184,700	18,490
Project expenses	**47,454**	46,312	**181,753**	144,193	14,576
Project other income (expense)[1]	**(2,141)**	(4,052)	**(3,858)**	7,749	(275)
Total project income	**14,605**	7,659	**57,247**	48,256	3,639
Administrative and other expenses					
Management fees, administration and other	**1,894**	1,693	**6,367**	5,095	1,270
Amortization of deferred financing costs	**287**	247	**1,029**	990	116
Interest, net	**9,858**	7,178	**31,589**	23,698	2,769
Distribution, non-controlling interest	**2,029**	4,340	**15,107**	20,578	2,622
Loss (income) from change in non-controlling interest liability	**1,647**	(10,588)	**3,691**	(10,588)	16,490
Foreign exchange loss (gain)	**(5,297)**	1,872	**1,295**	6,453	266
Total administrative and other expenses	**10,418**	4,742	**59,078**	46,226	23,533
Income (loss) before income taxes	**4,187**	2,917	**(1,831)**	2,030	(19,894)
Income taxes expense	**1,253**	179	**577**	2,539	–
Net income (loss)	**2,934**	2,738	**(2,408)**	(509)	(19,894)
Basic earnings (loss) per share, US$	**$0.06**	$0.06	**($0.05)**	($0.01)	(0.57)
Basic earnings (loss) per share, Cdn$	**$0.06**	$0.07	**($0.06)**	($0.02)	(0.69)
Diluted earnings (loss) per share, US$	**$0.05**	$0.06	**($0.05)**	($0.01)	(0.57)
Diluted earnings (loss) per share, Cdn$	**$0.06**	$0.07	**($0.06)**	($0.02)	(0.69)
Total assets at December 31	**1,176,275**	926,630	**1,176,275**	926,630	740,203
Total long-term liabilities at December 31	**1,012,876**	812,448	**1,012,876**	812,448	589,797
Cash flows from operating activities	**23,883**	19,473	**57,521**	38,370	12,897
Distributions declared					
Per IPS, US$	**0.25**	0.22	**0.94**	0.83	0.10
Per IPS, Cdn$	**0.27**	0.26	**1.04**	1.01	0.12

1 Includes equity in earnings from partnerships of $4,157 and $10,438 for the three and twelve month periods ended December 31, 2006 from five Projects in which Holdings owns interest of between 17.1% and 40.0%, accounted for on an equity basis.

Results of Operations for the Three- and Twelve-Month Periods Ended December 31, 2006

OVERVIEW

The financial results for the three- and twelve-month periods ended December 31, 2006 include contributions from Holdings' 40% indirect interest in the Chambers Project, acquired on September 8, 2005, while the comparative financial results for the same periods in 2005 included contributions from the Masspower Project, which was sold in the fourth quarter of 2005. The results of Path 15 Holdco are included from the date of acquisition, which was September 15, 2006. As of December 31, 2006, the Projects had PPAs with 17 customers. Details on several aspects of the PPAs for each Project are presented in the "Project Portfolio" section of this MD&A.

Project income is the primary GAAP measure of the Company's operating results and is discussed in the "Project Operations Performance – Three-Month Period Ended December 31, 2006" and "Project Operations Performance – Twelve-Month Period Ended December 31, 2006" sections below. In addition, an analysis of non-project expenses impacting the results of the Company is set out in the "Administrative and Other Expenses" section below.

Significant non-cash items, which are subject to potentially significant fluctuations, include: (1) the change in fair value of the non-controlling interest held in Holdings by the Existing Investors; (2) the non-cash portion of the foreign exchange gain or loss, reflecting the impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of the Company's Canadian dollar-denominated debt and the mark-to-market value of currency forward contracts; and (3) the non-cash portion of interest rate swaps that have been executed to fix the interest rate paid on Project-level non-recourse debt.

Cash flow available for distribution was $11,626 for the three months ended December 31, 2006 compared to $20,649 for the same period in 2005. For the twelve months ended December 31, 2006, cash flow available for distribution was $57,893, representing an increase of $9,213 over the same period in 2005. See the "Cash Flow Available for Distribution" section of this MD&A for additional information.

Net income for the three months ended December 31, 2006 was $2,934 compared to net income of $2,738 for the comparable period in 2005. The change reflects a 91% increase in project income, primarily attributable to the acquisition of Path 15 in the third quarter of 2006 and Chambers in the third quarter of 2005, partially offset by higher interest expense and a foreign exchange gain as compared to a foreign exchange loss in the prior year. In addition, distributions to non-controlling interest were lower in 2006 as a result of the redemption of Existing Investor interest in October 2005 and October 2006. The income statement impact of changes in the non-controlling interest liability resulted in a small loss in the fourth quarter of 2006, driven by increases in the market value of the IPSs up to the point that the final value of the liability was determined on December 20, 2006. In the prior year fourth quarter, a decrease in the market value of the IPSs resulted in a gain related to the non-controlling interest liability.

For the twelve months ended December 31, 2006, net loss increased to $2,408 from $509 over the same period in 2005 as a result of higher administrative and other expenses, primarily comprised of interest expense on higher outstanding debt balances and the absence of the large decrease in the non-controlling interest liability that occurred in 2005. These items were partially offset by improved project income due primarily to acquisitions, as well as lower distributions to non-controlling interest and a lower foreign exchange loss in the full-year 2006.

PROJECT INCOME

Project revenue increased 11% and 31% for the three- and twelve-month periods ended December 31, 2006, respectively. The increase for the three-month period is primarily attributable to the acquisition of Path 15 on September 15, 2006, partially offset by a decrease in revenue at Chambers attributable to lower dispatch. Higher revenues for the full-year 2006 are primarily attributed to the acquisition of Chambers in September 2005 and the acquisition of Path 15 described above. In addition, 2006 revenues were higher at Orlando due to higher volumes of electricity generated.

Project expenses increased by 26% for the twelve months ended December 31, 2006 compared to the prior year. $26.3 million of this increase is attributable to the acquisition of Chambers in September 2005. In addition, an unplanned outage at Pasco resulted in increased maintenance costs of approximately $3.5 million in 2006. Also, fuel costs were higher at Orlando due to higher generation output as described above.

Project other income (expense) primarily includes interest expense on non-recourse debt at the Projects and earnings from investments that are accounted for under the equity method of accounting.

Interest expense on debt at the Projects increased by $11.1 million to $16.8 million during the twelve months ended December 31, 2006 compared to the same period in the prior year. The increase was almost entirely attributable to the acquisitions of Chambers in the third quarter of 2005 and Path 15 in the third quarter of 2006. Both of these Projects contain debt that is serviced from the Project cash flows before distributions are made to the Company. The increase in interest expense for the three months ended December 31, 2006 over the same period in the prior year is also attributable to these acquisitions.

Equity earnings decreased by 24% to $10.4 million for the twelve months ended December 31, 2006 compared to the year ended December 31, 2005. This decrease is attributable to the sale of Masspower and lower earnings at Rumford. Partially offsetting these decreases is an increase at Selkirk. See "Project Operations Performance – Twelve-Month Period Ended December 31, 2006" in this MD&A for additional discussion of performance at these Projects. Equity earnings for the three-month period ended December 31, 2006 increased over the same period in the prior year for the same reasons.

ADMINISTRATIVE AND OTHER EXPENSES

Management fees and administration includes the costs of operating a public company, as well as the fees and costs associated with the Manager. The Manager is indirectly owned by the ArcLight Funds and receives compensation in the form of an annual base fee which is indexed to inflation and an incentive fee that is equal to 25% of cash distributions to IPS holders and Existing Investors in excess of Cdn$1.00 per year per IPS or Existing Investor membership interest. The Company also reimburses the Manager for reasonable costs incurred to manage the Company. The increase in management fees and other expenses in 2006 was primarily the result of higher professional fees related to documentation of internal controls for compliance with public company requirements, increased personnel costs due to corporate office staff additions, and higher management incentive fees due to increases in distributions to IPS holders. Partially offsetting these increases is a reduction in directors' and officers' liability insurance premiums.

Interest expense primarily relates to required interest payments to holders of the Subordinated Notes and the Debentures. The increase in net interest expense during 2006 is due to the issuance of the Debentures in October 2006, as well as the issuance of additional Subordinated Notes in October 2005 and in October and December of 2006. Earnings on higher levels of cash and cash equivalents invested throughout 2006, as well as higher short-term interest rates on these investments, partially offset this increase in interest expense.

Distributions to non-controlling interest represent distributions paid by Holdings on membership interest owned by the Existing Investors. These distributions decreased in 2006 as a result of redemptions of the Existing Investors' interest in Holdings that occurred in October 2005 and October 2006. As described in "Recent Transactions" in this MD&A, the Company acquired all of the remaining Existing Investors' interest in Holdings in February 2007 and, accordingly, no further distributions will be paid to the Existing Investors.

The loss (income) from change in non-controlling interest represents: (1) the change in the fair value of the liability during each period based on the market value of the IPSs at each balance sheet date; and (2) the reduction in the liability resulting from the redemptions of the Existing Investors' interest in Holdings that occurred in October 2005 and October 2006.

Prior to December 31, 2006, the non-controlling interest liability, was estimated at each balance sheet date based on the market value of the Company's IPSs at the balance sheet date multiplied by the number of membership interest in Holdings owned by the Existing Investors at that date. In December 2006, the final amount to be paid to the Existing Investors for its remaining interest in Holdings was determined based on the net price received per IPS for the Company's sale, on a private placement basis, of 8,600,000 IPSs (see "Recent Transactions" in this MD&A for additional information). As a result, the liability is recorded as $76.9 million at December 31, 2006 and this amount was paid to the Existing Investors in February 2007 to redeem their remaining interest in Holdings and the liability was extinguished. After December 31, 2006, the financial statements will no longer reflect income variations that are attributable to changes in the non-controlling interest liability.

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of the Company's Canadian dollar-denominated obligations to non-controlling interest and to holders of Subordinated Notes and Debentures, as well as the unrealized and realized gains and losses on the Company's forward contracts for the purchase of Canadian dollars for distributions on IPSs and non-controlling interest, and interest payments on Debentures. The U.S. dollar to Canadian dollar exchange rate was nearly the same on December 31, 2006 and 2005. However, the exchange rate did fluctuate throughout the year. As a result, the foreign exchange loss for the twelve months ended December 31, 2005 is $1.3 million. This loss is primarily due to the change in fair value of forward hedge contracts executed during 2006. For the three months ended December 31, 2006, the foreign exchange gain of $5.3 million is attributable to a strengthening U.S. dollar during the period.

SUPPLEMENTARY FINANCIAL INFORMATION

The key measure used by management to evaluate the results of the Company's investments is Cash Flow Available for Distribution. See the "Cash Flow Available for Distribution" section of this MD&A for additional details and for a reconciliation of Cash Flow Available for Distribution to its nearest GAAP measure, cash flows from operating activities.

The primary factor influencing Cash Flow Available for Distribution is cash distributions received from the Projects. These distributions received are generally funded from EBITDA generated by the Projects, reduced by Project-level debt service and capital expenditures, and adjusted for changes in Project-level working capital and cash reserves. Please read the "Non-GAAP Financial Measures" section of this MD&A for important disclosures with respect to Cash Flow Available for Distribution and EBITDA.

Because Project EBITDA and Project distributions are key drivers of both the performance of the Company's investments and Cash Flow Available for Distribution, this MD&A contains supplementary unaudited non-GAAP information that summarizes EBITDA by Project and a reconciliation of EBITDA by Project to Project distributions actually received by the Company.

Many of the Company's investments are either proportionately consolidated or accounted for under the equity method of accounting in the consolidated financial statements presented in accordance with GAAP. The proportionate consolidation method of accounting is applied by recording in the Company's consolidated financial statements its proportionate share of each financial statement account at the proportionately consolidated Project. As a result, some components of the Company's balance sheet contain assets that are not directly available to the Company in the normal course of business, or liabilities that are not direct obligations of the Company.

For example, the Company's proportionate share of cash at a proportionately consolidated Project is reflected in the consolidated balance sheet even though this cash may not be directly controlled by the Company because it is subject to: (1) the provisions of the partnership agreement that governs the underlying investment or; (2) in the case of Restricted Cash, the non-recourse debt covenants at the Projects. Conversely, the Company's proportionate share of debt at a proportionately consolidated Project is also reflected in the consolidated balance sheet notwithstanding that all of the Project-level debt at the Projects is secured by assets at the Projects and is non-recourse to the Company.

Beginning on page 34, tables of supplementary unaudited non-GAAP information segregate the consolidated statements of operations and the consolidated balance sheet into amounts attributable to consolidated and proportionately consolidated Projects and amounts attributable to corporate balances. In addition, a column is included that presents the Company's proportionate share of balance sheet and income statement items that are attributable to Projects accounted for under the equity method of accounting. These amounts attributable to Projects accounted for under the equity method of accounting are not included in the consolidated financial statements presented in accordance with GAAP and are provided for informational purposes only.

PROJECT OPERATIONS PERFORMANCE – THREE-MONTH PERIOD ENDED DECEMBER 31, 2006

Aggregate EBITDA at the Projects, including earnings from equity investments, was $37,701 during the fourth quarter of 2006, a 25% increase compared to the prior year fourth quarter. The fourth-quarter 2006 results included a full quarter of contribution from the Path 15 Project, which was acquired on September 15, 2006. Contributors to improved EBITDA included: (1) Selkirk, due to (i) operational variances attributable to the sale of excess natural gas supply at favourable market prices offset by lower energy margins, and (ii) a fourth-quarter 2005 reduction in EBITDA resulting from an adjustment to partnership income that is made on a semi-annual basis in accordance with the legal structure of the partnership; and (2) Gregory, due to higher levels of dispatch.

Partially offsetting these positive contributions was reduced EBITDA at: (1) Rumford, primarily due to its transition to a market-based interim PPA as of January 2006, and (2) at Chambers, due to lower dispatch.

Aggregate power generation declined 9% while plant availability increased 0.8% during the fourth quarter of 2006 compared to the same period in 2005. The comparative decrease in generation in the fourth quarter of 2006 was driven by: (1) Selkirk, due to a planned outage in October; and (2) Chambers, as a result of lower dispatch and reduced output due to a planned outage of one of the two boilers. Facilities in the Project portfolio achieved a 95.3% availability level for the fourth quarter of 2006, a slight increase from 94.5% for the same period in 2005.

PROJECT OPERATIONS PERFORMANCE – TWELVE-MONTH PERIOD ENDED DECEMBER 31, 2006

EBITDA at the Projects for the twelve-month period ended December 31, 2006 increased to $131,825, 17% over the level achieved for the same period in 2005. The twelve months of 2006 included the contributions from a full year of Chambers and a partial year of Path 15, improved margins at Lake due to a scheduled contractual increase in capacity payments and an increase in as-available energy sales; and an increase in contractual capacity payments for Selkirk's Consolidated Edison and Niagara Mohawk PPAs. There were also higher water flows at Topsham, leading to improved performance over the prior year.

Partially offsetting these positive contributions was the absence of any contribution from Masspower, which was sold in the fourth quarter of 2005; Rumford's reduced EBITDA due to both its transition to a market-based interim PPA and a third-quarter 2006 forced outage; and a first-quarter 2006 unplanned turbine outage at Pasco, which included voluntarily accelerated major maintenance and an upgrade to the plant's combustion turbines' output and efficiency.

Aggregate generation for the twelve-month period ended December 31, 2006 increased 12% compared to 2005. The main drivers were increases from: (1) the addition of Chambers, generation from the time of its acquisition in September 2005; and (2) increased dispatch at Mid-Georgia. The increases were partially offset by decreases from: (1) absence of Masspower generation since its sale in December 2005; (2) reduced generation at Selkirk, mainly due to scheduled maintenance in October and reduced dispatch; (3) reduced generation at Orlando; (4) reduced generation at Rumford, operating under a market-based PPA and a forced outage in the third-quarter of 2006; and (5) reduced generation at Pasco, due to a forced outage that included extended downtime to perform an upgrade to its gas turbines.

The aggregate plant availability level for 2006 of 96.8% did not change significantly from 2005.

Cash Flow from Operating Activities

The Company's cash flow from the Projects varies from year to year based on, among other things, changes in rates under the PPAs, fuel supply and transportation agreements, steam sales agreements and other Project contracts, compliance with the terms of non-recourse project-level financing including debt repayment schedules, the transition to market pricing following the expiry of PPAs, fuel supply and transportation contracts, working capital requirements and the operating performance of the Projects. Project cash flows themselves may have some seasonality and the pattern and frequency of distributions from the Projects to Holdings during the year can also vary.

The Company's cash flow from operating activities increased by 23% for the three-month period ended December 31, 2006 compared to the same period in the prior year. The increase was primarily attributable to lower restricted cash balances at the Projects, but also included normal fluctuations in many non-cash income statement items and routine changes due to timing differences in working capital.

The Company's cash flow from operating activities increased by 50% for the twelve-month period ended December 31, 2006 compared to the same period in the prior year. The increase was attributable to the lack of recurrence of non-cash items that were included in earnings in 2005. Examples of such items include the gain on the sale of Masspower and the recording of future income taxes recoverable in 2005. Without these non-cash earnings items in 2005, net income would have been higher in 2006 than in 2005.

Cash Flow Available for Distribution

Holders of IPSs receive cash distributions in the form of interest payments on Subordinated Notes and dividends on Common Shares. The Company increased the distribution to a rate of Cdn$1.03 per IPS annually, effective with the September 2005 distribution, and further increased the distribution to Cdn$1.06 per IPS annually effective with the September 2006 distribution, which latter increase was payable to holders of record as of September 29, 2006.

Cash flow available for distribution in the three months ended December 31, 2006 decreased over the same period in 2005 due to a number of factors, including a decrease in distributions received from equity investments, an increase in interest expense, the impact of a revision of the Company's income tax estimate for the full year of 2006 that was recorded in the fourth quarter, and lower realized gains on foreign currency transactions. For the full-year 2006, cash flow available for distribution increased over the full-year 2005, primarily as a result of higher operating cash flow, primarily driven by the acquisitions of Chambers and Path 15, partially offset by lower distributions from equity investments.

The Company evaluates its level of distributions with its Board of Directors by analyzing payout ratios and long-term cash flow projections, as well as the accretion to cash flow provided by acquisitions.

The table below presents the Company's calculation of Cash Available for Distribution for the three- and twelve-month periods ended December 31, 2006 and 2005.

(In thousands of U.S. dollars, except as otherwise stated)	Three months ended December 31		Twelve months ended December 31	
(unaudited)	**2006**	2005	**2006**	2005
Cash flows from operating activities	**23,883**	19,473	**57,521**	38,370
Project-level debt repayment	**(11,441)**	(10,052)	**(27,185)**	(20,679)
Interest IPS portion of Subordinated Notes	**7,723**	6,009	**26,464**	20,346
Net income tax installments recoverable	**(8,124)**[1]	768	**4,734**[1]	7,682
Purchase of property, plant and equipment	**(415)**	(1,068)	**(3,641)**	(2,558)
Cash flow available for distribution, US$	**11,626**	20,649	**57,893**	48,680
Cash flow available for distribution, Cdn$	**13,272**	24,013	**67,399**	58,981
Interest on IPS Subordinated Notes	**7,723**	6,009	**26,464**	20,346
Dividends on IPS Common Shares	**5,187**	3,751	**16,985**	12,102
Total IPS distributions, US$	**12,910**	9,760	**43,449**	32,448
Total IPS distributions, Cdn$	**14,776**	11,421	**49,151**	39,124
Cash flow available for distribution per basic IPS, Cdn$	**$0.25**	$0.54	**$1.45**	$1.53
Cash flow available for distribution per diluted IPS, Cdn$	**$0.23**	$0.54	**$1.42**	$1.53
Total distribution declared per IPS, Cdn$	**$0.27**	$0.26	**$1.04**	$1.01

1 Net income tax installments recoverable represents management's estimate of U.S. federal income tax installment payments that will be recovered in future periods. The amount presented is comprised of installment payments made during the period, offset by the current tax provision recorded in the consolidated statement of operations and deficit and any income tax refunds received. These adjustments have the effect of removing changes in working capital resulting from the timing of tax payments from the calculation of cash flow available for distribution.

Summary of Quarterly Results

Variations in quarterly results are driven by the following factors:

- Seasonality of Project revenues created by seasonal variances in demand for electric power, in some cases varied seasonal pricing for portions of the PPA payments and relatively small amounts of uncontracted output, and the typical scheduling of major facility maintenance in the spring and fall.
- Variations in cash flow may also be driven by the timing of Project-level debt payments (i.e., most are quarterly and some semi-annual), as distributions from the Projects to the Company must occur in conjunction with the passing of certain tests at those payment dates.
- Non-cash charges, principally: (1) the change in fair value of the non-controlling investors, which is based on the change in the price of IPSs from period to period; (2) the non-cash portion of the foreign exchange gain or loss, reflecting the impact of foreign exchange fluctuations from period to period on the U.S. equivalent of the Company's Canadian dollar-denominated debt and the mark-to-market value of currency forward contracts; and (3) the non-cash portion of interest rate swaps that have been executed to fix the interest rate paid on project-level non-recourse debt.

The table below presents selected quarterly consolidated financial data for the eight most recently completed fiscal quarters.

Selected Quarterly Consolidated Financial Data (in thousands of U.S. dollars, except as otherwise stated)

	2005				**2006**			
(unaudited)	Q1	Q2	Q3	Q4	**Q1**	**Q2**	**Q3**	**Q4**
Project revenues	37,863	37,966	50,848	58,023	**55,107**	**58,030**	**65,521**	**64,200**
Net income (loss)	9,942	(5,326)	(7,863)	2,738	**3,321**	**4,656**	**(13,319)**	**2,934**
Cash flow from operating activities	4,557	8,098	6,242	19,473	**8,027**	**15,978**	**9,633**	**23,883**
Cash distributions	7,495	7,385	7,808	9,760	**9,952**	**10,273**	**10,314**	**12,910**
Cash available for distribution	7,350	11,551	9,130	20,649	**10,243**	**21,309**	**14,715**	**11,626**
Payout ratio	102%	64%	86%	47%	**97%**	**49%**	**70%**	**111%**
Per IPS statistics								
Net income (loss) – basic	0.27	(0.14)	(0.21)	0.06	**0.08**	**0.11**	**(0.30)**	**0.06**
Net income (loss) – diluted	–	–	–	–	**–**	**–**	**–**	**0.05**
Cash flow from operating activities	0.12	0.22	0.17	0.44	**0.18**	**0.36**	**0.25**	**0.45**
Cash available for distribution, US$	0.20	0.31	0.25	0.47	**0.23**	**0.48**	**0.33**	**0.22**
Cash available for distribution, Cdn$	0.24	0.38	0.30	0.54	**0.27**	**0.54**	**0.38**	**0.25**
Distributions, US$	0.20	0.20	0.21	0.22	**0.23**	**0.23**	**0.23**	**0.25**
Distributions, Cdn$	0.25	0.25	0.25	0.26	**0.26**	**0.26**	**0.26**	**0.27**

Liquidity and Capital Resources

The Company's primary source of cash and cash equivalents is distributions from the Projects. Substantially all of the cash received from Project distributions is distributed in the form of interest and dividends to holders of the IPSs, the Separate Subordinated Notes or the Debentures. The Company plans to maintain the stability and sustainability of cash distributions to holders of IPSs, and to increase, when prudent, dividends on the Common Shares. Future increases in dividends on the Common Shares will be achieved if the Company is successful in maximizing the performance of existing Projects and making accretive acquisitions. The Company may fund future acquisitions with a combination of cash on hand, the issuance of additional debt or equity securities and the incurrence of bank debt.

Management believes that the Company will be able to generate sufficient amount of cash and cash equivalents to maintain the Company's operations and meet obligations as they become due. The following additional sources of liquidity, in addition to cash flow from operations, are available to the Company.

CREDIT FACILITY

Holdings maintains a revolving credit facility in the amount of $75 million. The facility expires in November 2008. Loans outstanding under the credit facility bear interest at LIBOR plus a margin of 1.5%. As of December 31, 2006, $13,465 was allocated, but not drawn, to support letters of credit for contingent liabilities at several Projects. In the second quarter of 2006, $10,000 previously drawn on the credit facility was repaid. As at December 31, 2006, no loans were outstanding under the credit facility and the amount available for loans or letters of credit was $61,535.

RESTRICTED CASH

At December 31, 2006, Restricted Cash included Project-level reserve accounts and amounts held in escrow for the redemption of the Existing Investors that occurred in February 2007.

The Projects generally have reserve requirements to support payments for major maintenance costs and project-level debt service. For Projects that are consolidated or proportionately consolidated with Atlantic Power, these amounts, or Atlantic Power's portion of these amounts, are reflected as Restricted Cash on the Company's consolidated balance sheet. At December 31, 2006, Restricted Cash at consolidated and proportionately consolidated Projects totalled approximately $37.4 million. All Project-level debt is non-recourse to the Company or Holdings and is fully amortized over the life of the Projects' PPAs.

At certain of the Projects, a portion of the Restricted Cash represents reserves for debt service that are required by Project-level financing arrangements. In some, but not all, cases where a Project-level debt service reserve is represented by Restricted Cash, it is possible for the Company to replace its proportionate share of the debt service reserve with a letter of credit under the revolving credit facility. If the Company chose to replace the Restricted Cash with a letter of credit, the Restricted Cash could be released and distributed to the Company. This represents an additional source of liquidity that the Company may consider for funding acquisitions or other general corporate purposes.

In December 2006, the Company sold 8,600,000 IPSs in a private placement transaction. See "Recent Transactions" in this MD&A for additional details. The proceeds from the private placement transaction were used in February 2007 to acquire all of the remaining interest of the Existing Investors in Holdings. The net proceeds from the private placement transaction were deposited into an escrow account until regulatory approval was received in February 2007 for the transaction, in which the Company acquired all of the remaining interest of the Existing Investors in Holdings. The balance in the escrow account was $74,433 at December 31, 2006 and is included in Restricted Cash in the consolidated balance sheet. The entire balance in the escrow account was paid to the Existing Investors in February 2007.

PATH 15 ACQUISITION CREDIT FACILITY

The acquisition of the Path 15 Project on September 15, 2006 was initially financed with an acquisition credit facility in the amount of $88,000 (the "Acquisition Credit Facility") at Atlantic Holdings. Loans under the Acquisition Credit Facility bear interest at a rate equal to a eurodollar rate or a U.S. base rate, plus an applicable margin to those rates. As of December 31, 2006, the applicable rate, including margin, was 7.35% on the eurodollar loan outstanding on the Acquisition Credit Facility.

In October 2006, approximately $37 million of the net proceeds of the Company's public offering of IPSs and Debentures were applied to repay a portion of the principal amount outstanding on the Acquisition Credit Facility. In January 2007, the Company made an additional $20 million payment on the Acquisition Credit Facility. In March 2007, the remaining balance due on the Acquisition Credit Facility was repaid using funds drawn from Holdings' revolving credit facility. Management intends to enter into a permanent financing arrangement for the acquisition of the Path 15 Project in the second quarter of 2007. The final amount to be borrowed under the permanent financing arrangement has not been determined, but it is expected to be in the range of $50 million to $60 million and will be non-recourse to the Company.

RESERVE FUND

In order to contribute to the Company's ability to provide holders of IPSs with stable and sustainable cash distributions, the Company established a Reserve Fund at the closing of the IPO to stabilize future cash distributions and fund acquisitions and other growth opportunities. The Company maintains a balance of approximately $10 million in the Reserve Fund, which is invested in highly liquid securities rated, Aa or better. The Reserve Fund is not legally restricted and is included in cash and cash equivalents in the consolidated balance sheets of the Company. The Reserve Fund was not utilized to fund the acquisition of the Path 15 Project in September 2006.

INFORMATION REGARDING GUARANTORS

The Subordinated Notes and the Debentures are secured by a pledge of the Company's membership interest in Atlantic Holdings and are guaranteed by Atlantic Holdings and Teton Power Funding, LLC, Epsilon Power Funding, LLC, MP Power LLC, Teton East Coast Generation LLC, Teton Fuels Mid-Georgia LLC, Teton Selkirk LLC, Badger Power Generation I LLC, Badger Power Generation II LLC, Baker Lake Hydro LLC, Dade Investment, L.P., Geddes II Company LLC, Geddes Cogeneration Company LLC, MEP Rumford, LLC, NCP Dade Power LLC, NCP Houston Power LLC, NCP Pasco LLC, NCP Perry LLC, Olympia Hydro LLC, Onondaga Cogeneration Limited Partnership, Orlando Power Generation I LLC, Orlando Power Generation II LLC, Stockton Cogen (II) LLC, Teton New Lake, LLC and Teton Operating Services, LLC (the "Guarantors"). The guarantee of Atlantic Holdings is secured by a pledge of its membership interest in Teton Power Funding, LLC and Epsilon Power Funding, LLC. The guarantees of certain of the Guarantors are secured by pledges of the membership interest or other securities they hold in subsidiary entities subject to the provisions of agreements governing or affecting interest in such subsidiaries which may restrict or prevent pledges in certain cases.

The consolidated financial statements of the Company include the consolidated financial results of the Company and its Guarantor and non-Guarantor subsidiaries. Summary unaudited consolidating financial information of the Company, the Guarantors and the non-Guarantor subsidiaries of the Company as at and for the twelve-month period ended December 31, 2006 is presented in the table below. The selected financial information for the Company and for the Guarantors includes certain investments in subsidiaries accounted for on a cost basis and is therefore not presented in accordance with GAAP.

	Atlantic Power Corporation	Guarantor subsidiaries	Non-Guarantor subsidiaries	Consolidation adjustments	Consolidated
Income statement					
Project revenue	–	2,265	240,593	–	242,858
Project expenses	–	1,148	180,605	–	181,753
Project other income (expense)	–	67	(3,925)	–	(3,858)
Project income	–	1,184	56,063	–	57,247
Dividends received	46,647	88,644	–	(135,291)	–
Administrative and other expenses	36,262	7,053	–	15,763	59,078
Income (loss) before income taxes	10,385	82,775	56,063	(151,054)	(1,831)
Income taxes	518	59	–	–	577
Income (loss)	9,867	82,716	56,063	(151,054)	(2,408)
Balance sheet					
Current assets	11,196	153,374	128,022	(21,434)	271,158
Investment in Guarantor subsidiaries	493,942	–	–	(493,942)	–
Investment in non-Guarantor subsidiaries	–	561,234	–	(561,234)	–
Other non-current assets	14,918	4,038	890,456	(4,295)	905,117
Total non-current assets	508,860	565,272	890,456	(1,059,471)	905,117
	520,056	718,646	1,018,478	(1,080,905)	1,176,275
Current liabilities	28,346	57,163	80,612	56,123	222,244
Non-current liabilities	393,375	20,624	376,633	–	790,632
Shareholders' equity	98,335	640,859	561,233	(1,137,028)	163,399
	520,056	718,646	1,018,478	(1,080,905)	1,176,275

Project Portfolio

The following table outlines the Company's portfolio of power generating assets as of December 31, 2006, including its interest in each facility. Management believes the portfolio is well diversified based on electricity and steam buyers, regulatory jurisdictions and regional power pools, thereby mitigating exposure to market, regulatory or environmental conditions specific to any single region.

Project Name	Location	Fuel Type	Total MW	Ownership Interest [1]	Acct'g Tmt [2]	Net MW [3]	Electricity Off-Taker	PPA Expiry	Off-Taker S&P Credit Rating
Badger Creek	California	Natural gas	46	50.0%	P	23	Pacific Gas & Electric	2011	BBB
Chambers	New Jersey	Coal	262	40.0%	P	74 16 15	Atlantic City Electric DuPont Merchant [4]	2024 2024 N/A	BBB AA- N/A
Delta-Person	New Mexico	Natural gas	132	40.0% [5]	E	53	Public Service of New Mexico	2020	BBB
Gregory	Texas	Natural gas	400	17.1%	E	59 9	Constellation Energy Reynolds Metals	2008 2020	BBB N/R
JPPC	Jamaica	Fuel oil	60	24.1%	E	14	Jamaica Public Service	2018	B
Koma Kulshan	Washington	Hydro	13	49.8%	P	6	Puget Sound Energy	2037	BBB-
Lake	Florida	Natural gas	110	100.0%	C	110	Progress Energy Florida	2013	BBB+
Mid-Georgia	Georgia	Natural gas	308	50.0%	P	154	Georgia Power	2028	A
Onondaga	New York	Natural gas	91	100.0%	C	91	Niagara Mohawk	2008 [6]	A
Orlando	Florida	Natural gas	126	50.0%	P	44 19	Progress Energy Florida Reedy Creek Improvement District	2023 2013	BBB+ A- [9]
Pasco	Florida	Natural gas	121	49.9%	P	60	Progress Energy Florida	2008	BBB+
Path 15	California	Transmission	N/A	100.0%	C	N/A	California Utilities via CAISO [10]	N/A [11]	BBB to A [12]
Rumford	Maine	Coal/biomass	85	23.5% [5]	E	20	Rumford Paper Co. [7]	2009	N/R
Selkirk	New York	Natural gas	345	18.5% [5]	E	15 49	Niagara Mohawk Consolidated Edison	2008 2014	A A
Stockton	California	Coal	55	50.0%	P	24 3	Pacific Gas & Electric Corn Products Int'l	2008 2008	BBB BBB-
Topsham [8]	Maine	Hydro	14	50.0%	P	7	Central Maine Power	2011	BBB

1 Except as otherwise noted, economic interest represents the percentage ownership interest in each Project held indirectly by Atlantic Holdings.
2 Accounting treatment: C – Consolidated; P – Proportionate consolidation; E – Equity method (see Note 1 to the Consolidated Financial Statements for additional details).
3 Represents the interest of Atlantic Holdings in each Project's electricity generation capacity based on Atlantic Holdings' economic interest in each Project.
4 The merchant output of the facility is sold by Atlantic City Electric in the spot market through a profit-sharing arrangement with Chambers.
5 Represents Atlantic Holdings' estimate of its share of the cash flow from the project.
6 A swap agreement with Niagara Mohawk Power Corporation has replaced the Onondaga PPA.
7 For further information, see the discussion of the new interim financial consolidation agreement with the former Mead/Westvaco paper mill (now owned by NewPage) under "Project Descriptions – Rumford Project".
8 Atlantic Holdings owns its interest in this Project as a lessor.
9 Rating from Fitch.
10 California utilities pay Transmission Access Charges ("TACs") to California Independent System Operator, who owners of Transmission System Rights, such as Path 15, in accordance with its FERC-approved annual revenue requirement.
11 Path 15 is a FERC-regulated asset with a FERC-approved regulatory life of 30 years, through 2034.
12 The largest payers of TACs supporting Path 15's annual revenue requirement are PG&E (BBB), SoCal Ed (BBB+) and SDG&E (A). CAISO imposes minimum credit quality requirements for any participants of A or better unless collateral is posted per CAISO imposed schedule.

Capital Expenditures

Capital expenditures for the Projects are made at the Project level using Project cash flows and Project reserves. Therefore, the distributions that Holdings receives from the Projects are made net of capital expenditures needed at the Projects and the Company has not to date needed to inject funds into the Projects for ongoing capital expenditures. The Projects in which the Company has investments generally consist of large capital assets that have established commercial operations. Ongoing capital expenditures for assets of this nature are generally not significant because most major expenditures relate to planned repairs and maintenance and are expensed when incurred.

Contractual Obligations

As of December 31, 2006 (in thousands of U.S. dollars)		Payment due by period			
(unaudited)	Total	2007	2008 to 2010	2011 to 2012	Thereafter
Long-term debt (a)	414,373	85,242	74,155	47,231	207,745
Subordinated Notes (b)	336,840	–	–	–	336,840
Convertible Debentures (c)	51,485	–	–	51,485	–
Total contractual obligations	802,698	85,242	74,155	98,716	544,585

A. LONG-TERM DEBT

Long-term debt represents the Company's consolidated and proportionately consolidated share of Project long-term debt. The amount presented excludes the net unamortized purchase price adjustment of $14,207 related to the fair value of debt assumed in the Path 15 acquisition. Project debt is non-recourse to the Company and amortizes during the term of the respective revenue-generating contracts of the Projects. The range of interest rates on long-term Project debt at December 31, 2006 was 3.25% to 9.5%.

B. SUBORDINATED NOTES

As of December 31, 2006, the Company had a $336,840 outstanding principal amount of Subordinated Notes due 2016. The notes pay only interest at a rate of 11% until their maturity.

C. CONVERTIBLE DEBENTURES

The Debentures pay interest semi-annually on April 30 and October 31 of each year, commencing on April 30, 2007. The Debentures mature on October 31, 2011 and are convertible into approximately 80.6452 IPSs per Cdn$1,000 principal amount of Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per IPS.

D. PROJECT CONTRACTS

Each Project typically has a set of contracts that include the following obligations of the Project partnerships, all of which are non-recourse to the Company. Therefore, specific contracts for individual Projects are not discussed in detail in the MD&A or included in the Contractual Obligations table above. The following are general characteristics of typical contracts at the Projects:

- PPAs generally allow Projects to pass through their fuel costs. See the table in the "Project Portfolio" section of this MD&A with respect to off-takers and durations.
- Fuel supply agreements may have minimum volume requirements.
- Fuel transportation agreements incorporate capacity reservation/demand payments for natural gas, or shipping cost per ton of coal.
- Steam sales agreements typically have a tenor that matches that of the related PPA and are designed to meet regulatory requirements for thermal load/efficiency at fossil fuel plants.

- Operating and maintenance agreements provide for services provided by third parties or owners.
- Long-term service agreements may be in place for gas or steam turbine inspections and overhauls.
- Site lease agreements grant use of Project land where the Project does not own the site.

Further information about the Projects' agreements is contained in the Company's Annual Information Form dated March 28, 2007, which is available on SEDAR's website at www.sedar.com.

E. FINANCIAL INSTRUMENT CONTRACTS

Please see the discussion in the "Financial and Other Instruments" section of this MD&A.

F. CREDIT FACILITY

Please see the discussion in the "Liquidity and Capital Resources" section of this MD&A.

G. MANAGEMENT AND INCENTIVE FEES

The Company pays a management fee under the management agreement executed in November 2004 among the Company, Holdings and the Manager (the "Management Agreement") that is subject to adjustment for acquisitions as agreed to by the Company and the independent members of Holdings' Board of Managers, plus incentives, inflation adjustment and expenses. See "Related Party Transactions" in this MD&A for additional details. The Company paid the Manager $894 and $435 in aggregate base management and incentive fees during the twelve months ended December 31, 2006 and 2005, respectively.

Related Party Transactions

The Manager has been engaged under the Management Agreement to provide certain management and administrative services to the Company and Holdings, for which it is paid: (1) an annual base management fee; (2) reimbursement of costs; and (3) an incentive fee equal to 25% of the excess in distributions paid to IPS holders and Existing Investors during the year above Cdn$1.00 per IPS. The Management Agreement has an initial term of 20 years from the IPO completed in November 2004. The Company paid the Manager $340 and $300 for the annual base management fee, $554 and $135 in incentive fees and $3,005 and $2,554 for cost reimbursements during the years ended December 31, 2006 and 2005, respectively.

The Manager receives administrative and office support services from ArcLight under a management support agreement executed in November 2004 among the Manager, ArcLight and the Company. This agreement also requires the ArcLight Funds and their affiliates to give the Manager the opportunity to pursue, on behalf of the Company and Holdings, investment opportunities that do not fit within the investment guidelines for the ArcLight Funds or other investment funds managed by ArcLight or its affiliates.

Through December 1, 2006, the Manager sublet its office space from ArcLight Capital Partners, LP ("ArcLight") under a sublease agreement. The agreement was terminated on December 1, 2006.

The Manager is owned indirectly by the ArcLight Funds. Subsidiaries of the ArcLight Funds, in conjunction with a subsidiary of Caithness, owned 41.9% of Holdings' common membership interest after the IPO, but reduced their interest to 29.9% in October 2005 and further reduced their interest to approximately 14.0% in October 2006. In February 2007, the Company acquired all of the remaining interest of the Existing Investors in Holdings.

As of the date hereof, there are six members of the Board of Managers of Holdings, consisting of the four directors of the Company as well as the President and Chief Executive Officer and the Chief Financial Officer of the Manager. These two individuals may not vote on any proposed acquisitions by Holdings of projects in which the ArcLight Funds have an ownership interest.

At the time of the IPO, Holdings was granted a right of first offer ("ROFO") on eleven power-producing projects owned by the ArcLight Funds. The acquisition of a 40% indirect interest in Chambers Cogeneration LP in September 2005 is the only asset that has been acquired under the terms of the ROFO agreement. As of December 31, 2006, a 90 MW project located in Florida is the only project that remains subject to the ROFO agreement.

Caithness has an indirect ownership interest in one of the Existing Investors. Subsidiaries of Caithness provide operations, maintenance and accounting at four of the Projects and administrative and project management functions for an additional eight Projects under agreements which are in effect until December 2011 and renewable thereafter. During the three- and twelve-month periods ended December 31, 2006, Holdings incurred fees and expenses of $688 and $2,976, respectively, for these services provided by Caithness.

Financial and Other Instruments

The Company uses forward foreign currency contracts to manage its exposure to changes in foreign exchange rates, as the Company earns its income principally in the United States and has the obligation to make distributions predominantly in Canadian dollars. Since its inception, the Company has established a hedging strategy for the purpose of reinforcing the long-term sustainability of its distributions. The Company has executed this strategy by entering into forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make monthly distributions through December 2011 at the current annual distribution level of Cdn$1.06 per IPS to all holders including the Existing Investors, as well as interest payments on the Subordinated Notes. It is the Company's intention to periodically extend the length of these forward contracts by one additional year. Changes in the fair market value of the Company's forward contracts partially offset exchange gains or losses on the U.S. dollar equivalent of the Company's Canadian dollar obligations. The following table summarizes the Company's forward foreign currency contracts with monthly settlement terms as of December 31, 2006:

Notional monthly amounts

Period	Sell U.S. dollars	Buy Cdn. dollars	Average rate
Current–2009	4,811	5,800	1.2055
2010	5,167	5,800	1.1225
2011	5,494	5,800	1.0557

In addition to the forward contracts in the table above that settle on a monthly basis, the Company has executed forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make semi-annual payments on the Debentures. The contracts provide for the purchase of Cdn$2.1 million and Cdn$1.9 million in April 2007 and October 2007, respectively, at a rate of 1.1240 Canadian dollars per U.S. dollar and the purchase of Cdn$1.9 million in April and in October of 2008 through 2011 at a rate of 1.1075 Canadian dollars per U.S. dollar.

The foreign exchange forward contracts are carried at estimated fair value based on quoted market value. Mark-to-market adjustments of the foreign currency forward contracts are reflected in foreign exchange gains and losses. The foreign exchange contracts are classified as other assets. See "Results of Operations for the Three- and Twelve-Month Periods Ended December 31, 2006 – Administrative Expenses" in this MD&A for additional details related to foreign exchange gains and losses recognized.

Certain of the Projects also use interest rate swaps to manage fluctuations in interest rates and natural gas forwards or swaps to minimize the effects on cash flow of changing natural gas prices, which are a major component of Project expenses. Some of these contracts have been designated as hedges for accounting purposes. In addition, other Projects have entered into natural gas contracts with pricing terms designed to minimize the impact of gas price volatility on operating margins.

The Company has an Indexed Swap under which it receives monthly payments based upon the differential between an indexed contract price and a market reference price for electricity through June 2008. In order to lock in favourable gas, power, and capacity pricing under the Indexed Swap, the Company has entered into an Indexed Swap Hedge. For further details on the Indexed Swap Hedge, please see Note 8 of the Company's audited consolidated financial statements for the twelve months ended December 31, 2006.

The values of all the financial instruments described above are subject to changes in market prices. Management of the Company monitors these risks and the market values of these financial instruments and periodically reviews its risk management strategies as market conditions change.

Accounting Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates. During the periods presented, management has made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment and PPAs, the recoverability of equity investments, the recoverability of future tax assets and the fair value of financial instruments and derivatives.

The Company has acquired the majority of its long-term assets through acquisitions. In applying the purchase method of accounting, the Company is required to estimate the fair value of the assets acquired including the property, plant and equipment and intangible assets. The determination of these fair values is complex and involves significant judgments.

Revenue recognition is based on monthly invoices by the Projects to electricity and steam buyers and, for one Project which has fluctuating rates over time, the average rate over the term of the PPA is used for revenue with the difference between cash received and revenue recognized as deferred revenue. Fixed asset valuations of power plants are based on depreciated replacement cost. Valuations of PPAs and fuel supply agreements are based on the incremental net present value of cash flows provided by the agreement as compared to the merchant value of the plant. The Company typically uses outside consultants to determine the merchant value of a facility. On an ongoing basis, the Company monitors the performance of the facilities to determine if any recoverability issues exist or if any change in the useful life of the facility is required.

The future tax asset valuation allowance has been determined pursuant to the provisions of The Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, *Income Taxes*, including the Company's estimation of future taxable income, where necessary, and is adequate to reduce the total future tax asset to an amount that will more likely than not be realized. The Company incurred taxable income for the nine-month period ended December 31, 2005 and taxable income for the nine-month period ended December 31, 2006. During the third quarter of 2006, the Company completed its 2005 tax returns and recorded an income tax benefit in the amount of $2.2 million, representing an adjustment in the estimated amounts of tax that were previously recorded. The Company has provided a valuation allowance to reduce net future tax assets to an amount expected to be recovered in the foreseeable future.

The fair values of financial instruments and derivatives such as the forward foreign currency contracts, interest rate swaps and natural gas swaps are typically based on market quotes. The Company also has an Indexed Swap and related hedge agreement, which is discussed in Note 8 to the Company's audited consolidated financial statements for the twelve months ended December 31, 2006. The fair values of these agreements are based on estimated future cash flows and take into account certain assumptions, including forecasts or future energy prices, inflation rates, discount rates and credit risk. Energy prices can be volatile and other assumptions can change from period to period. These factors can create significant fluctuations in the estimated fair values of these agreements.

For additional information regarding accounting policies and estimates, please see Note 1 of the Company's audited consolidated financial statements for the twelve months ended December 31, 2006.

Recent Accounting Pronouncements

FINANCIAL INSTRUMENTS – RECOGNITION AND MEASUREMENT

In January 2005, the CICA released Handbook Section 3855, *Financial Instruments – Recognition and Measurement,* effective for annual and interim periods beginning on or after October 1, 2006. This section establishes standards for the recognition and measurement of all financial instruments, provides a characteristics-based definition of a derivative financial instrument, provides criteria to be used to determine when a financial instrument should be recognized, and provides criteria to be used when a financial instrument is to be extinguished.

COMPREHENSIVE INCOME AND EQUITY

In January 2005, the CICA released new Handbook Section 1530, *Comprehensive Income*, and Section 3251, *Equity*, effective for annual and interim periods beginning on or after October 1, 2006. Section 1530 establishes standards for reporting comprehensive income. These standards require that an enterprise present comprehensive income and its components in a separate financial statement that is displayed with the same prominence as other financial statements. Section 3251 establishes standards for the presentation of equity and changes in equity during the reporting period in addition to the requirements in Section 1530.

HEDGES

In January 2005, the CICA released new Handbook Section 3865, *Hedges*, effective for annual and interim periods beginning on or after October 1, 2006. This new section establishes standards for when and how hedge accounting may be applied. Hedge accounting is optional.

All of the new pronouncements described above will be implemented by the Company as of January 1, 2007. The Company is in the process of finalizing its implementation of these new standards and assessing the impact on its consolidated financial position and results of operations.

Commitments and Contingencies

The Chambers partnership, in which Holdings owns a 40% indirect interest, filed suit against its coal supplier, Consol Pennsylvania Coal Company and related entities, over a disagreement involving the pricing of a portion of the annual coal deliveries to the plant. Chambers was seeking, among other things: (1) a declaratory judgment regarding the terms of the agreement; (2) damages for missed deliveries; and (3) injunctive relief to ensure delivery of all coal requested under the contract. The coal supplier had asserted affirmative defenses and counterclaims in its answer. In the third quarter of 2006, the matter was settled for an amount that was not material to the Project.

The Rumford cogeneration facility purchases its coal from Massey Coal Sales Company ("Massey"). Massey's coal is delivered through a Sprague Energy Corp. ("Sprague") marine terminal. Massey and Sprague had disputed terms and compensation for certain terminal services provided by Sprague, and Massey had asserted that Rumford also had failed to pay certain amounts due under the coal supply agreement. In the third quarter of 2006, the dispute was settled for an amount that was not material to the Project.

From time to time, the Company and its subsidiaries and Projects are parties to disputes and litigation that arise in the normal course of business. The Company assesses its exposure to these matters and records estimated loss contingencies when a loss is likely and can be reasonably estimated. There were no matters pending as of December 31, 2006 which are expected to have a material impact on the Company's financial position or results of operations.

Outstanding Share Data

The Company had 61,470,500 IPSs outstanding at December 31, 2006 compared to 44,339,500 IPSs outstanding at December 31, 2005. As of March 27, 2007, 61,470,500 IPSs were outstanding.

The Debentures are convertible to approximately 80.6452 IPSs per Cdn$1,000 principal amount of Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per IPS. As of December 31, 2006, approximately 4,838,700 IPSs would be required to be issued if all of the outstanding Debentures were converted to IPSs.

Outlook

In order to maintain stable distributions and provide long-term growth, the Company will continue to focus on enhancing the financial performance of the existing Projects and pursuing accretive acquisitions predominantly in the U.S. market.

PPAs in the portfolio have various expiration dates as listed in the "Project Portfolio" table in this MD&A. In each case, the Project's partners plan for such expirations by evaluating various options in the market in order to continue maximizing Project cash flows. For example, partners of Projects with PPA expirations in 2008 have already begun efforts to provide for potential new or extended PPAs. The new agreements may involve responses to utility solicitations for capacity, direct negotiations with the original purchasing utility for PPA extensions, arrangements with other creditworthy parties for tolling agreements, and PPAs or the use of derivatives to lock in stable power and/or fuel prices beyond the spot markets. Management has not assumed that pricing under existing PPAs will necessarily be sustained after PPA expirations.

In 2009, the gas supply agreement at Lake will expire, whereas the PPA extends until 2013. While it is still somewhat early to work on extending this agreement or entering into a new agreement, management is monitoring forward prices in that market. The current gas agreement provides pricing that is currently below market, so management assumes that margins at Lake may fall in 2010 and beyond. Other options to maximize cash flow at Lake include a PPA restructuring and extension, and an analysis is being performed on a possible upgrade of the Project's turbines.

Risk Factors

Atlantic Power's future performance and its ability to generate sufficient cash flow to meet its monthly cash distributions to holders of IPSs, and the Common Shares and Subordinated Notes represented thereby, and to holders of Debentures, are subject to a number of risks and uncertainties. Any of these risks and uncertainties could have a material adverse effect on the Company's results of operations, business prospects, financial condition, the cash available to the Company for distribution to holders of IPSs, Common Shares, Subordinated Notes or Debentures or on the market price or value of IPSs, Common Shares or Subordinated Notes. In addition to the summary of certain risk factors below and other information contained or incorporated by reference in this MD&A, the "Risk Factors" section of the Company's Annual Information Form dated March 28, 2007 should be given careful consideration and is incorporated by reference herein. Additional risks and uncertainties not currently known to the Company or management of the Manager, or that the Company or management of the Manager currently consider immaterial, may also impair operations of the Company. If any such risks actually occur, the business, financial condition, or liquidity and results of operations of the Company, and the ability of the Company to make distributions on the IPSs, the Common Shares and Subordinated Notes represented thereby, and the Debentures, could be materially adversely affected. The Company's annual information form is available on SEDAR's website at www.sedar.com.

The following is a summary of the primary risks facing the Company, with further discussion of risk factors found in the Company's Annual Information Form dated March 28, 2007.

REVENUE MAY BE REDUCED UPON EXPIRATION OR TERMINATION OF PPAS

Power generated by the Projects, in most cases, is sold under PPAs that expire at various times. In addition, these PPAs may be subject to termination in certain circumstances, including default by the Project owner or operator. When a PPA expires or is terminated, it is possible that the price received by the relevant Project for power under subsequent arrangements may be reduced significantly. It is possible that subsequent PPAs may not be available at prices that permit the operation of the Project on a profitable basis. If this occurs, the affected Project may temporarily or permanently cease operations.

THE PROJECTS DEPEND ON THEIR ELECTRICITY AND THERMAL ENERGY CUSTOMERS

Each Project relies on one or more PPAs, steam sales agreements or other agreements with one or more utilities or other customers for a substantial portion of its revenue. The amount of cash available for distribution to holders of IPSs, Common Shares and Subordinated Notes is highly dependent upon customers under such agreements fulfilling their contractual obligations. There is no assurance that these customers will perform their obligations or make required payments to the Project operating entities.

CERTAIN PROJECTS ARE EXPOSED TO FLUCTUATIONS IN THE PRICE OF ELECTRICITY AND FUELS

While a majority of the off-takers of the Projects are contractually obligated to purchase electricity output under long-term PPAs, and a portion of the revenues under the contracts is typically a relatively fixed capacity payment, variable payments made for energy produced will depend on escalators based on fluctuations in electricity and/or fuel prices and possibly inflation, which may not effectively hedge the Project's operating margins relative to changes in variable inputs. In addition, should any of the long-term PPAs expire or terminate, the Manager or the relevant Project operator will be required to either negotiate new PPAs or sell into the electricity wholesale market, in which case the changed price relationships between electricity revenues and variable inputs may result in operating margin reduction or elimination.

PREDICTING PROJECT CASH FLOWS OVER THE LONG TERM IS DIFFICULT

Due to the many uncertainties described in this "Risk Factors" section that could materially affect future revenues or expenses, it can be difficult to make long-term projections of the Company's operating margins.

OPERATIONS ARE SUBJECT TO THE PROVISIONS OF VARIOUS ENERGY LAWS AND REGULATIONS

Generally, in the United States, the Company's projects are subject to regulation by the FERC regarding the terms and conditions of wholesale service and rates, as well as by state agencies regarding PPAs entered into by Qualify Facility ("QF") projects and the siting of the generation facilities. The majority of the Company's generation is sold by QF projects under PPAs that required approval by state authorities.

On August 8, 2005, the Energy Policy Act of 2005 ("EPAct 2005") was enacted, removing certain regulatory constraints on investment in utility power producers by repealing the Public Utility Holding Company Act of 1935 ("PUHCA 1935") and enacting the Public Utility Holding Company Act of 2005 ("PUHCA 2005"). EPAct 2005 also limited the requirement that electric utilities buy electricity from QFs in certain markets that lack competitive characteristics. Finally, EPAct 2005 amended and expanded the reach of FERC's corporate merger approval authority under Section 203 of the Federal Power Act ("FPA"). Over the last several months, FERC has issued final rulemakings implementing these provisions of EPAct 2005.

If any Project that is a QF were to lose its status as a QF, then such Project may no longer be entitled to exemption from the provisions of PUHCA 2005 or from provisions of the FPA and state law and regulations. Loss of QF status could trigger defaults under covenants to maintain QF status in the PPAs, steam sales agreements and Project-level debt agreements and result, if not cured within specified cure periods, in the termination of agreements, penalties or the acceleration of indebtedness under such agreements, plus interest.

The Projects would also have to file with FERC for market-based rates or file for acceptance of the rates set forth in the applicable PPA, and its rates would then be subject to initial and potentially subsequent reviews by FERC under the FPA, which could result in reductions to the rates.

In connection with its first transmission investment, Path 15, the Company will be required to have its Path 15 operating subsidiary make a triennial filing with the FERC for review of certain aspects of its rate recovery, such as the allowed return on equity. The first such filing will be in late 2007 for the 2008–2010 rate recovery period. While the Company believes that Path 15's current rate recovery assumptions are supported both by other recent analogous FERC precedents and recent FERC policy statements, it is possible that such rate reviews will result in a lower allowed return on equity or other changes that could have a material affect on the project's revenues.

EPAct 2005 provides incentives for various forms of electric generation technologies, which may subsidize our competitors. In addition, EPAct 2005 requires the FERC to select an industry self-regulatory organization which will impose mandatory reliability rules and standards. Among other things, FERC's rules implementing these provisions allow such reliability organizations to impose sanctions on generators that violate their new reliability rules.

The Company's projects require licenses, permits and approvals which may be in addition to any required environmental permits. No assurance can be provided that we will be able to obtain, comply with or renew as required all necessary licenses, permits and approvals for these facilities. If we cannot comply with and renew as required all applicable regulations, our business, results of operations and financial condition could be adversely affected.

We cannot provide assurance that the introductions of new laws, or other future regulatory developments, will not have a material adverse impact on our business, operations or financial condition.

PROJECTS ARE SUBJECT TO SIGNIFICANT AIR EMISSIONS REGULATIONS

Environmental laws and regulations have generally become more stringent over time, and this trend may continue. In particular, the U.S. Environmental Protection Agency, or EPA, has recently promulgated regulations requiring additional reductions in nitrogen oxides, or NO_X, and sulfur dioxide, or SO_2, emissions, commencing in 2009 and 2010, respectively, and has also promulgated regulations requiring reductions in mercury emissions from coal-fired electricity generating units, commencing in 2010 with more substantial reductions in 2018.

Moreover, certain of the states in which we operate have promulgated air pollution control regulations which are more stringent than existing and proposed federal regulations. Specifically, there is a proposed multi-state carbon cap-and-trade program known as the Regional Greenhouse Gas Initiative ("RGGI"), which would apply to the Company's fossil-fuel facilities in the northeast, primarily Chambers and Rumford, which utilize coal. A model rule for implementation of RGGI is expected to be released within the next few months.

In 2006, the State of California passed legislation initiating two programs to control/reduce the creation of greenhouse gases ("GHG"). The two laws, more commonly known as Assembly Bill ("AB") 32 and Senate Bill ("SB") 1368, are currently in the regulatory rulemaking phase, which will involve public comment and negotiations over specific provisions.

Under AB 32, a GHG emissions cap is mandated on all major sources (not limited to the electric sector). In order to do so, regulations will be adopted for the mandatory reporting and verification of GHG emissions and to reduce statewide emissions of GHG to 1990 levels by 2020. This will most likely require that electricity generating facilities reduce their emissions of GHG or pay for the right to emit by the implementation date of January 1, 2012. The program has yet to be finalized and the decision as to whether allocations will be distributed or auctioned will be determined in the rulemaking process that is currently underway. This could affect the Company's coal-fired Stockton Project and to a much lesser extent, if at all, its Badger Creek Project.

SB 1368 added the requirement to establish a GHG emission performance standard and implement regulations for power purchase agreements that exceed five years and are entered into prospectively by publicly-owned electric utilities. Provisions are under consideration in the rulemaking to allow facilities that have higher CO_2 emissions to be able to negotiate PPAs for up to a five-year period or sell power to entities not subject to SB 1368. This statute may limit the Stockton Project's ability to extend its PPA with Pacific Gas & Electric (which currently expires in early 2008) beyond the five-year limit.

In addition to the regional initiatives, legislation for the regulation of GHG has been introduced at the federal level and, if passed, may eventually override the regional efforts with a national cap-and-trade program.

THE PROJECTS DEPEND ON SUPPLIERS UNDER FUEL SUPPLY AGREEMENTS AND INCREASES IN FUEL COSTS MAY ADVERSELY AFFECT THE PROFITABILITY OF THE PROJECTS

Revenues in respect of the Projects may be affected by the availability, or lack of availability, of a stable supply of fuel at reasonable prices. To the extent possible, the Projects attempt to match fuel costs to PPA energy payments. To the extent that fuel costs are not matched directly to PPA energy payments, increases in fuel costs may adversely affect the profitability of the Projects.

The amount of energy generated at the Projects is highly dependent on suppliers under certain fuel supply and transportation agreements fulfilling their contractual obligations. The loss of significant fuel supply agreements or the inability or failure of any supplier to meet its contractual commitments may adversely affect cash distributions by the Company. The amount of energy generated at the Projects is also dependent upon the availability of natural gas, coal, oil or biomass. There can be no assurance of the long-term availability of such resources.

Upon the expiry or termination of existing fuel supply or transportation agreements, the Manager or Project operators will have to renegotiate these agreements or may need to source fuel from other suppliers. There can be no assurance that the Manager or Project operators will be able to renegotiate these agreements or enter into new agreements on similar terms. Furthermore, there can be no assurance as to the availability of the supply or the pricing of fuel under new arrangements. The gas supply contract expiration in 2009 at the Company's Lake Project is discussed in the "Outlook" section of this MD&A.

U.S. FEDERAL INCOME TAX RISKS

There can be no assurance that U.S. federal income tax laws and IRS administrative policies respecting the U.S. federal income tax consequences generally applicable to a holder of Common Shares and Subordinated Notes, as represented by IPSs, will not be changed in a manner which adversely affects non-U.S. holders.

There is no authority that directly addresses the tax treatment of securities similar to the Subordinated Notes as part of a unit that includes Common Shares of the Company. In light of this absence of direct authority, it cannot be concluded with certainty that the Subordinated Notes will be treated as debt for U.S. federal income tax purposes and, although the Company intends to take the position that the Subordinated Notes are debt for U.S. federal income tax purposes, there can be no assurance that this position will not be challenged by the IRS. If such a challenge were sustained, interest payments on the Subordinated Notes would be recharacterized as non-deductible distributions with respect to the Company's equity, and the Company's net taxable income and thus its U.S. federal income tax liability would be materially increased. As a result, the Company's after-tax cash flow would be reduced and the Company's ability to make interest payments on Subordinated Notes and distributions with respect to Common Shares could be materially and adversely impacted.

RECENT CANADIAN FEDERAL INCOME TAX PROPOSALS

On December 21, 2006, the Department of Finance (Canada) released for public comment draft legislation significantly modifying the income tax rules applicable to certain publicly listed trusts and partnerships. An investment in IPSs does not involve a publicly listed trust or partnership but an investment in IPSs does share certain characteristics with investments in publicly listed trust or partnership entities that are the subject of the draft legislation and the proposals first announced on October 31, 2006. The proposals of October 31, 2006 indicated that although the details outlined therein reflected the then current intentions of the Canadian government, any aspect of the measures may be changed accordingly, and possibly with retroactive effect, if there should emerge structures or transactions that are clearly devised to frustrate the policy objectives underlying the proposals. Management believes that the proposed rules do not apply to the Company and do not alter the tax consequences of an investment in Common Shares and Subordinated Notes represented by IPSs. However, there is no assurance that the December 21, 2006 draft legislation and, more generally, Canadian federal income tax laws and administrative policies, will not be changed in a manner that adversely affects the holders of Common Shares and Subordinated Notes represented by IPSs.

Disclosure Controls and Procedures

Based on the requirements of Multilateral Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, the Chief Executive Officer and Chief Financial Officer of the Manager have evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Multilateral Instrument 52-109) as of December 31, 2006. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of the Manager have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2006 to provide reasonable assurance that material information relating to the Company would be made known to them by others within the Company.

The Company's management has designed its internal control over financial reporting as of December 31, 2006 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with GAAP.

Additional Information

Additional information is available on the Company's website at www.atlanticpowercorporation.com, or under the Company's profile on the SEDAR website at www.sedar.com.

The following tables present unaudited non-GAAP supplementary financial information provided for informational purposes. Please see "Non-GAAP Financial Measures" and "Results of Operations for the Three- and Twelve-Month Periods Ended December 31, 2006 – Supplementary Financial Information" for additional details about the supplementary information.

Project EBITDA[1] (in thousands of U.S. dollars)	Three months ended December 31		Twelve months ended December 31	
(unaudited)	**2006**	2005	**2006**	2005
EBITDA from consolidated and proportionately consolidated Projects				
Badger Creek	**1,290**	1,176	**4,188**	4,656
Chambers	**3,684**	7,152	**23,984**	9,058
Koma Kulshan	**107**	245	**758**	694
Lake	**6,612**	7,217	**28,970**	25,957
Mid-Georgia	**688**	1,769	**4,461**	5,251
Onondaga	**938**	(427)	**5,267**	3,939
Orlando	**2,361**	3,204	**10,040**	8,998
Pasco	**3,226**	3,836	**9,761**	13,782
Stockton	**1,014**	586	**1,915**	2,577
Topsham	**812**	560	**2,523**	1,449
Path 15	**7,815**	–	**9,270**	–
Other	**164**	–	**645**	426
Total EBITDA from consolidated and proportionately consolidated Projects	**28,711**	25,318	**101,782**	76,787
Amortization	**11,965**	13,607	**40,676**	36,280
Interest expense, net	**6,298**	1,139	**16,795**	5,712
Other income	**–**	–	**(2,499)**	–
Earnings from consolidated and proportionately consolidated Projects	**10,448**	10,572	**46,810**	34,795
EBITDA from equity Projects				
Delta-Person	**529**	484	**2,457**	1,984
Gregory	**2,176**	1,307	**6,066**	5,278
Jamaica	**741**	607	**3,432**	3,935
Masspower	**–**	(298)	**–**	3,186
Rumford	**237**	1,861	**1,479**	7,238
Selkirk	**5,443**	801	**16,838**	14,281
Other	**(136)**	71	**(229)**	(124)
Total EBITDA from equity Projects	**8,990**	4,833	**30,043**	35,778
Amortization	**3,369**	9,162	**13,061**	20,088
Interest expense, net	**1,488**	843	**5,892**	6,433
Other (income) expense	**(72)**	(2,405)	**170**	(5,015)
Income tax	**48**	146	**482**	811
Equity earnings, net	**4,157**	(2,913)	**10,438**	13,461
Project income				
Total EBITDA from all Projects	**37,701**	30,151	**131,825**	112,565
Amortization	**15,334**	22,769	**53,737**	56,368
Interest expense, net	**7,786**	1,982	**22,687**	12,145
Other (income) expense	**(72)**	(2,405)	**(2,329)**	(5,015)
Income tax	**48**	146	**482**	811
Project income	**14,605**	7,659	**57,248**	48,256
Earnings from consolidated and proportionately consolidated Projects	**10,448**	10,572	**46,810**	34,795
Equity earnings, net	**4,157**	(2,913)	**10,438**	13,461
Project income	**14,605**	7,659	**57,248**	48,256

1 EBITDA, earnings before interest, taxes, depreciation and amortization, is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP. Management uses aggregate EBITDA at the Projects as a cash flow measure to provide comparative information about Project performance.

Reconciliation of Project Distributions (in thousands of U.S. dollars)

For the twelve months ended December 31, 2006 (unaudited)	EBITDA	Indexed swap and hedge settlements and other Income	Repayment of long-term debt	Interest expense, net	Capital expen-ditures	Change in working capital and other items	Project distribution received
Consolidated and proportionately consolidated Projects							
Lake	28,970	–	(108)	32	(716)	483	28,660
Chambers	23,984	–	(9,550)	(8,969)	(225)	1,068	6,307
Orlando	10,040	–	(3,461)	(227)	–	898	7,250
Pasco	9,761	–	(5,198)	(792)	(1,395)	3,177	5,553
Path 15	9,270	–	(3,779)	(3,235)	–	4,539	6,795
Onondaga	5,267	22,742	–	67	–	(10,501)	17,575
Mid-Georgia	4,461	–	(2,228)	(3,169)	–	935	–
Badger Creek	4,188	–	–	41	–	(479)	3,750
Topsham	2,523	–	(1,885)	(586)	–	(52)	–
Stockton	1,915	–	–	114	(1,242)	1,213	2,000
Koma Kulshan	758	–	(976)	(71)	(63)	352	–
Other	645	–	–	–	–	(645)	–
Total consolidated and proportionately consolidated Projects	101,782	22,742	(27,185)	(16,795)	(3,641)	988	77,890
Equity Projects							
Selkirk	16,838	–	(4,290)	(3,464)	(107)	(733)	8,245
Gregory	6,066	–	(743)	(1,140)	(210)	(3,972)	–
Jamaica	3,432	–	(1,626)	(571)	(1,187)	73	120
Delta-Person	2,457	–	(795)	(1,000)	–	(662)	–
Rumford	1,479	–	–	145	(206)	902	2,320
Masspower	–	–	–	–	–	–	–
Other	(229)	–	–	138	–	1,205	1,115
Total equity Projects	30,043	–	(7,454)	(5,892)	(1,710)	(3,187)	11,800
Total all Projects	131,825	22,742	(34,639)	(22,687)	(5,351)	(2,199)	89,690

Supplementary Income Statement Information (in thousands of U.S. dollars)

For the twelve months ended December 31, 2006 (unaudited)	Consolidated and proportionately consolidated projects	Proportionate consolidation of equity investments[1]	Corporate
Income Statement			
Project revenue			
Energy sales	224,626	123,244	–
Transmission services	10,090		
Indexed swap	4,509	–	–
Other	3,633	12,575	–
	242,858	135,819	–
Project expenses			
Fuel	92,150	81,450	–
Operations and maintenance	42,176	16,997	–
Project operator fees and expenses	6,751	7,499	–
Amortization	40,676	13,061	–
	181,753	119,007	–
Project other income (expense)			
Interest expense, net	(16,795)	(5,891)	–
Other income	2,499	–	–
Income tax expense	–	(483)	–
	(14,296)	(6,374)	–
Project income	46,809	10,438	–
Administrative and other expenses			
Management fees and administration	–	–	6,367
Amortization of deferred financing costs	–	–	1,029
Interest, net	–	–	31,589
Distribution, non-controlling interest	–	–	15,107
Loss (income) from change in non-controlling interest liability	–	–	3,692
Foreign exchange loss	–	–	1,295
	–	–	59,079
Income (loss) before income taxes	46,809	10,438	(59,079)
Income taxes	–	–	577
Net income (loss)	46,809	10,438	(59,656)

1 Non-GAAP measure showing the composition of revenues and expenses based on the Company's proportionate ownership of the Projects accounted for under the equity method.

Supplementary Income Statement Information (in thousands of U.S. dollars)

As of December 31, 2006 (unaudited)	Consolidated and proportionately consolidated projects	Proportionate consolidation of equity investments[1]	Corporate
Assets			
Current assets			
Cash and cash equivalents	21,677	5,710	46,950
Restricted cash	37,433	19,081	74,433
Current portion of indexed swap	33,016	–	–
Accounts receivable	37,465	9,262	(1,410)
Prepayments, supplies and other	8,592	4,237	587
Income tax receivable	–	–	12,415
	138,183	38,290	132,975
Property, plant and equipment	411,180	65,958	–
Transmission system rights	218,846		
Power purchase agreements	85,274	65,298	–
Goodwill	79,158	–	–
Long-term portion of indexed swap	17,108	–	–
Deferred financing costs	215	15	10,775
Other	1,702	2,220	3,886
	951,666	171,781	147,636
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities	28,220	9,663	2,613
Revolving credit facility	–	–	–
Current portion of long-term debt	35,168	9,358	51,000
Deferred revenue	6,833	–	–
Current portion of indexed swap hedge	11,612	–	–
Interest payable on Subordinated Notes	–	–	3,873
Distribution payable, non-controlling interest	–	–	669
Dividends payable	–	–	1,872
Other	3,578	–	–
	85,411	19,021	60,027
Long-term debt	342,412	70,735	–
Subordinated Notes	–	–	336,840
Convertible Debentures	–	–	51,484
Other liabilities, non-controlling interests	–	–	76,888
Indexed swap hedge	7,377	–	–
Deferred tax liability	12,050	–	5,052
Other liabilities	35,417	5,052	–
	482,667	94,808	530,291
Shareholders' equity			
Common stock	–	–	216,636
Project equity	468,999	76,973	(545,972)
Deficit	–	–	(53,236)
	468,999	76,973	(382,572)
	951,666	171,781	147,719

1 Non-GAAP measure showing the composition of assets and liabilities based on the Company's proportionate ownership of the Projects accounted for under the equity method.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

To the Shareholders of Atlantic Power Corporation

The accompanying consolidated financial statements of Atlantic Power Corporation, the management discussion and analysis and the information included in this annual report have been prepared by Atlantic Power Management, LLC, the Corporation's management, which is responsible for their consistency, integrity and objectivity. Management is also responsible for ensuring that the consolidated financial statements are prepared and presented in accordance with Canadian generally accepted accounting principles, which include amounts that are based on estimates and judgments. To fulfill these responsibilities, management maintains appropriate internal control systems and policies and procedures to provide reasonable assurance that assets are safeguarded and financial records are reliable and form a proper basis for the preparation of financial statements.

KPMG LLP, the Corporation's independent auditors, are responsible for auditing the consolidated financial statements in accordance with Canadian generally accepted accounting principles, and have expressed their opinion on the consolidated financial statements in this report. Their report, as auditors, is set forth below.

The Corporation's Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board of Directors carries out this responsibility through its Audit Committee, which meets regularly with management and the independent auditors. The members of the Audit Committee are independent of management. The consolidated financial statements have been reviewed and approved by the Board of Directors and its Audit Committee. The independent auditors have direct and full access to the Audit Committee and the Board of Directors.

Barry Welch
PRESIDENT AND CEO

Patrick Welch
CHIEF FINANCIAL OFFICER

AUDITORS' REPORT

To the Shareholders of Atlantic Power Corporation

We have audited the consolidated balance sheets of Atlantic Power Corporation as at December 31, 2006 and 2005 and the consolidated statements of operations and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and 2005 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

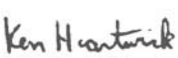
Chartered Accountants
TORONTO, CANADA MARCH 27, 2007

Consolidated Balance Sheets (in thousands of U.S. dollars)

December 31, 2006 and 2005	2006	2005
Assets		
Current assets:		
Cash and cash equivalents	$ 68,627	$ 43,858
Restricted cash (note 2)	111,866	26,758
Current portion of indexed swap (note 15)	33,016	46,558
Accounts receivable	36,055	28,708
Prepayments, supplies and other	9,179	7,902
Income tax receivable	12,415	7,682
	271,158	161,466
Property, plant and equipment (note 4)	411,180	428,479
Transmission system rights (note 6)	218,846	–
Equity investments (note 5)	76,973	78,335
Other intangible assets (note 6)	85,274	174,677
Goodwill	79,158	–
Long-term portion of indexed swap (note 15)	17,108	61,356
Deferred financing costs	10,990	10,643
Other assets	5,588	11,674
	$ 1,176,275	$ 926,630
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 30,833	$ 28,002
Revolving credit facility (note 7)	–	10,000
Current portion of long-term and short-term debt (note 8)	86,168	21,558
Current portion of indexed swap hedge (note 15)	11,612	25,094
Interest payable on Subordinated Notes	3,873	2,303
Distribution payable, non-controlling interest	669	1,429
Non-controlling interest liability (note 11)	76,888	–
Dividends payable	1,872	1,258
Other	10,329	3,719
	222,244	93,363
Long-term debt (note 8)	342,413	224,482
Subordinated Notes (note 9)	336,840	251,844
Convertible Debentures (note 10)	51,484	–
Other liabilities, non-controlling interest (note 11)	–	169,479
Indexed swap hedge (note 15)	7,377	33,453
Future tax liability (note 13)	17,101	–
Other liabilities	35,417	39,827
Shareholders' equity:		
Common stock (note 12)	216,635	148,025
Deficit	(53,236)	(33,843)
	163,399	114,182
Commitments and contingencies (note 14)		
Subsequent events (notes 2, 7 and 11)		
	$ 1,176,275	$ 926,630

See accompanying notes to consolidated financial statements.

On behalf of the Board:




Ken Hartwick
Director

Irving Gerstein
Director

Consolidated Statements of Operations and Deficit (in thousands of U.S. dollars, except per share amounts)

Years ended December 31, 2006 and 2005	2006	2005
Project revenue:		
Energy sales	$ 224,626	$ 173,841
Transmission services	10,090	–
Indexed swap (note 15)	4,509	6,339
Other	3,633	4,520
	242,858	184,700
Project expenses:		
Fuel	92,150	71,346
Operations and maintenance	42,176	30,158
Project operator fees and expenses (note 16)	6,751	6,409
Depreciation and amortization	40,676	36,280
	181,753	144,193
Project other income (expense):		
Equity earnings, net (note 5)	10,438	8,446
Interest expense, net	(16,795)	(5,712)
Gain on disposal of equity investment	–	5,015
Other income	2,499	–
	(3,858)	7,749
Project income	57,247	48,256
Administrative and other expenses:		
Management fees and administration (note 16)	6,367	5,095
Amortization of deferred financing costs	1,029	990
Interest, net	31,589	23,698
Distribution, non-controlling interest	15,107	20,578
Loss (income) from change in non-controlling interest liability	3,691	(10,588)
Foreign exchange loss	1,295	6,453
	59,078	46,226
Income (loss) before income taxes	(1,831)	2,030
Income taxes (note 13)	577	2,539
Loss for the year	(2,408)	(509)
Deficit, beginning of year	(33,843)	(21,232)
Dividends	(16,985)	(12,102)
Deficit, end of year	$ (53,236)	$ (33,843)
Loss per share (note 18):		
Basic	$ (0.05)	$ (0.01)
Diluted	(0.05)	(0.01)

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows (in thousands of U.S. dollars)

Years ended December 31, 2006 and 2005	2006	2005
Cash flows from (used in) operating activities:		
Loss for the year	$ (2,408)	$ (509)
Items not involving cash:		
Depreciation and amortization	41,705	37,270
Equity earnings	(10,438)	(8,446)
Change in non-controlling interest liability	3,691	(10,588)
Amortization of gas transportation contracts	(6,594)	(7,300)
Foreign exchange loss	5,220	8,281
Market value adjustments on indexed swap and hedge	(4,509)	(6,339)
Amortization of other liabilities and deferred revenue	389	1,959
Change in fair value of interest rate swaps	(1,769)	(4,432)
Loss (gain) on disposal of equity investments and property, plant and equipment	550	(5,015)
Future income taxes	–	(6,420)
Other	8,823	369
Change in non-cash operating working capital	(11,680)	(2,654)
Indexed swap and hedge settlements	22,741	26,270
Distributions from equity investments	11,800	15,924
	57,521	38,370
Cash flows from (used in) financing activities:		
Proceeds from issuance of common stock	69,150	26,644
Proceeds from issuance of Subordinated Notes	87,050	37,730
Common stock issuance costs	(3,383)	–
Deferred financing costs	(4,690)	(239)
Proceeds from short-term debt	88,000	–
Proceeds from convertible debentures	52,780	–
Proceeds from draw on revolving credit facility	–	25,000
Repayment of revolving credit facility	(10,000)	(15,000)
Repayment of debt	(64,185)	(20,679)
Dividends paid	(16,371)	(12,182)
Repayment of obligations to non-controlling interest	(87,287)	(64,374)
Cash deposited in escrow for redemption (note 11)	(74,433)	–
	36,631	(23,100)
Cash flows from (used in) investing activities:		
Proceeds on disposal of equity investment	–	59,365
Acquisitions, net of cash acquired (note 2)	(65,743)	(63,391)
Purchase of property, plant and equipment	(3,640)	(2,558)
	(69,383)	(6,584)
Increase in cash and cash equivalents	24,769	8,686
Cash and cash equivalents, beginning of year	43,858	35,172
Cash and cash equivalents, end of year	$ 68,627	$ 43,858
Supplemental cash flow information:		
Interest paid	$ 47,381	$ 35,958

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2006 and 2005 (In thousands of U.S. dollars)

Atlantic Power Corporation (the "Company") is a corporation established under the laws of the Province of Ontario on June 18, 2004 and continued in the Province of British Columbia on July 8, 2005. The Company issued income-participating securities ("IPSs") for cash pursuant to an initial public offering on November 18, 2004. Prior to November 18, 2004, the Company was inactive.

The Company formed Atlantic Power Holdings, LLC ("Atlantic Holdings"), a Delaware limited liability company, for the purpose of acquiring indirect interest in 15 projects from Teton Power Holdings, LLC, Epsilon Power Holdings, LLC and Umatilla Power Holdings, LLC (the "Existing Investors") and acquired the interest in these projects that were held by wholly owned subsidiaries of the Existing Investors.

The Company currently owns indirect interest in 15 power generation projects and one transmission line located primarily in the United States of America (collectively, the "Projects" and individually, "Project"). Three of the Projects are wholly owned subsidiaries of the Company, being Onondaga Cogeneration Limited Partnership ("Onondaga"), Lake Cogen Ltd. and Atlantic Holdings Path 15, LLC ("Path 15").

1. Significant accounting policies

A. BASIS OF CONSOLIDATION

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles and include the consolidated accounts of all its subsidiaries. The Company applies the equity method of accounting for investments in which it has significant influence but does not control. The Company proportionately consolidates investments in which it has joint control. The Company eliminates intercompany accounts and transactions.

B. CASH AND CASH EQUIVALENTS

Cash and cash equivalents include cash deposited at banks and highly liquid investments with original maturities of three months or less.

C. RESTRICTED CASH

Restricted cash represents cash and short-term investments that are maintained by the Projects to support payments for major maintenance costs and to meet Project-level contractual debt obligations. In addition, at December 31, 2006, $74,433 of restricted cash represents amounts held in escrow for the February 2007 transaction in which the Company acquired all of the remaining interest in Atlantic Holdings from the Existing Investors.

D. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost, net of accumulated depreciation. Depreciation is provided on a straight-line basis over the estimated useful life of the related asset. The useful lives of facilities range from three to 33 years. The weighted average useful life is 23 years.

E. TRANSMISSION SYSTEM RIGHTS

Transmission system rights are an intangible asset that represents the long-term right to approximately 72% of the capacity of the Path 15 transmission line in California (see note 2(A)). Transmission system rights are amortized on a straight-line basis over 30 years, the regulatory life of the Project.

F. GOODWILL

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the assets acquired, less liabilities assumed, based on their fair values. Goodwill is allocated, as of the date of the business combination, to the Company's reporting units that are expected to benefit from the synergies of the business combination.

Goodwill is not amortized and is tested for impairment annually, or more frequently if events or changes in circumstances indicate that the asset might be impaired. The impairment test is carried out in two steps. In the first step, the carrying amount of the reporting unit is compared with its fair value. When the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not to be impaired and the second step of the impairment test is unnecessary.

The second step is carried out when the carrying amount of a reporting unit exceeds its fair value, in which case the implied fair value of the reporting unit's goodwill is compared with its carrying amount to measure the amount of the impairment loss, if any. The implied fair value of goodwill is determined in the same manner as the value of goodwill is determined in a business combination, using the fair value of the reporting unit as if it was the purchase price. When the carrying amount of reporting unit goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess and is presented as a separate line item in the consolidated statements of operations and deficit before extraordinary items and discontinued operations.

G. OTHER INTANGIBLE ASSETS

Other intangible assets include power purchase contracts and fuel supply agreements.

Power purchase contracts are valued at the time of acquisition based on the rates received under the power purchase contracts relative to projected market rates. The balances are presented net of accumulated amortization. Amortization is recorded on a straight-line basis over the remaining term of the contract. The amortization period ranges from one to 19 years. The weighted average period of amortization is ten years.

Fuel supply agreements are valued at the time of acquisition based on the rates projected to be paid under the fuel supply agreement relative to projected market rates. The amortization period ranges from four to 18 years. The weighted average period of amortization is ten years.

H. REVENUE RECOGNITION

Generally, the Company recognizes energy sales revenue when electricity and steam are delivered under the terms of the related contracts. If the power purchase contract contains capacity payments that fluctuate over the term of the contract, then the Company recognizes revenue based on the estimated average rate for the duration of the contract, with the difference between cash received and revenue recognized reflected as deferred revenue.

Transmission services revenue is recognized as transmission services are provided. The annual revenue requirement for transmission services is regulated by the Federal Energy Regulatory Commission ("FERC") and is established through a rate-making process that occurs every three years. When actual cash receipts from transmission services revenue are different from the regulated revenue requirement because of timing differences, the over or under collections are deferred until the timing differences reverse in future periods.

Onondaga recognizes revenue as the swap agreements it has entered into settle monthly, net of any change in the fair value of these swap agreements (note 15).

I. 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 income in the year of enactment or substantive enactment.

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

J. GAS TRANSPORTATION CONTRACT LIABILITY

Onondaga has certain long-term commitments for the provision of natural gas transportation services to the Onondaga project through the year 2013. The contracts provide for fixed monthly demand charges, in addition to variable commodity charges based on the quantity of gas transported. Obligations related to the long-term gas transportation agreements were recognized as liabilities in purchase accounting upon the acquisition of Onondaga by the Company. These obligations are being amortized over the remaining lives of the contracts.

All of the Company's other gas transportation costs are expensed as incurred.

K. ACCOUNTING FOR DERIVATIVES

The Company uses financial derivative agreements in the form of interest rate swaps and foreign exchange forward contracts to manage its current and anticipated exposure to fluctuations in interest rates and foreign currency exchange rates. On occasion, the Company has also entered into natural gas supply contracts and natural gas forwards or swaps to minimize the effects of the price volatility of natural gas, which is a major production cost. The Company does not enter into financial derivative agreements for trading or speculative purposes; however, not all derivatives qualify for hedge accounting.

Derivative financial instruments not designated as a hedge are measured at fair value, with changes in fair value recorded in the consolidated statements of operations and deficit. Derivative financial instruments not designated as hedges are the foreign currency forward contracts, the indexed swap and indexed swap hedge agreements and certain interest rate swaps. Mark-to-market adjustments of the foreign currency forward contracts are reflected in foreign exchange loss, indexed swap and indexed swap hedge agreements are netted and reflected as indexed swaps under project revenue, and adjustments of interest rate swaps are reflected in project interest expense in the consolidated statements of operations and deficit.

Effectiveness tests are performed to evaluate hedge effectiveness at inception and on an ongoing basis, both retroactively and prospectively. Unrealized gains or losses on the interest rate swaps designated within a designated hedging relationship are not recognized.

Gains and losses on natural gas forward contracts and swaps that are designated as a hedge of fuel costs are recognized in income as actual fuel costs are recognized.

Natural gas supply contracts in the normal course of business, in which the Company takes possession of natural gas, are treated as executory contracts.

L. ASSET RETIREMENT OBLIGATIONS

The fair value of estimated asset retirement obligations is recognized in the consolidated balance sheets 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 included in depreciation expense in the consolidated statements of operations and deficit. 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 and deficit. Actual expenditures incurred are charged against the accumulated obligation.

M. IMPAIRMENT OF LONG-LIVED ASSETS

Long-lived assets such as property, plant and equipment, transmission system rights and other intangible assets subject to depreciation and amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to the estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds the fair value of the asset.

N. DEFERRED FINANCING COSTS

Deferred financing costs consist of loan fees and other costs of financing that are amortized over the term of the related financing using the straight-line method. The amortization period is the term of the debt.

O. FOREIGN CURRENCY TRANSLATION

The Company's functional currency and reporting currency is the United States dollar. The functional currency of the Company's subsidiaries and other investments is the United States dollar. Monetary assets and liabilities denominated in Canadian dollars are translated into United States dollars using the rate of exchange in effect at the end of the year. All transactions denominated in Canadian dollars are translated into United States dollars at the exchange rate in effect at the transaction date. Foreign currency translation gains and losses are reflected in the consolidated statements of operations and deficit.

P. USE OF ESTIMATES

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, management has made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment and power purchase contracts, the recoverability of equity investments, the recoverability of future tax assets, 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. Acquisitions

A. PATH 15 ACQUISITION

On June 29, 2006, Atlantic Holdings agreed to indirectly acquire 100% of Trans-Elect NTD Holdings Path 15, LLC, which owns approximately 72% of the transmission system rights in the Path 15 transmission project (the "Path 15 Project") located in California. Subsequent to the acquisition, management changed the name of Trans-Elect NTD Holdings Path 15, LLC to Atlantic Holdings Path 15, LLC.

The acquisition of Path 15 closed on September 15, 2006 and was financed with an acquisition credit facility in the amount of $88,000 (the "Acquisition Credit Facility") at Atlantic Holdings. Loans under the Acquisition Credit Facility bear interest at a rate equal to Eurodollar rate or a U.S. base rate, plus an applicable margin to those rates. The Acquisition Credit Facility is secured by pledges of assets in certain wholly owned and other investment companies of the Company. As of December 31, 2006, the applicable rate, including margin, on the loan outstanding on the Acquisition Credit Facility was 7.33%. The Acquisition Credit Facility is included in current portion of long-term debt and short-term debt in the consolidated balance sheets and had an outstanding balance of $51 million at December 31, 2006. The remaining outstanding balance was paid in the first quarter of 2007 using cash on hand and funds drawn from the Company's revolving credit facility.

At the time of the acquisition, ratemaking issues related to the Path 15 Project were under FERC review, the outcome of which would determine the annual regulated revenues to be earned by Path 15 and any potential refund obligation associated with past revenue collections. Given the potential impact of the ruling on the cash flows of Path 15, the Company negotiated certain purchase price adjustments in the purchase and sale agreement in the event of an adverse outcome on two of these issues. Specifically, $24,100 of the purchase price was deposited into escrow pending the FERC's final determination on these two ratemaking issues.

In the fourth quarter of 2006, the FERC issued its final order on the ratemaking issues. The result of the decision by FERC is an annual reduction in regulated revenues of approximately $1,000 per year and a refund of previously collected revenues of approximately $3,900. As a result, $9,573 of the amount deposited in escrow was returned to the Company and the remaining balance in escrow was remitted to the selling parties. With the FERC matters resolved, the purchase price is now final and management has completed its determination of the fair value of the assets and liabilities acquired as follows:

	Preliminary purchase equation	Adjustments	Revised purchase equation
Working capital	$ 14,653	$ (2,172)	$ 12,481
Transmission system rights	217,578	3,385	220,963
Goodwill	32,412	(24,980)	7,432
Other long-term assets	738	–	738
Future tax liability	(20,463)	8,413	(12,050)
Long-term debt (excluding current portion)	(156,918)	5,781	(151,137)
Total purchase price	88,000	(9,573)	78,427
Less cash acquired	8,105	4,579	12,684
Cash paid, net of cash acquired	$ 79,895	$ (14,152)	$ 65,743

B. EPSILON POWER PARTNERS, LLC ACQUISITION

On September 8, 2005, the Company acquired Epsilon Power Partners, LLC ("Epsilon") for cash consideration of $65,008, including acquisition costs of $564. Epsilon owns a 40% interest in Chambers Cogeneration LP ("Chambers"), the owner and operator of a 262 megawatt pulverized coal-fired cogeneration facility located at E.I. DuPont de Nemours & Company's Chambers Works complex in southwestern New Jersey.

During the quarter ended September 30, 2006, determination of the fair value of the power purchase and other contracts was finalized. The purchase price allocation has been adjusted as follows:

	Preliminary purchase equation	Adjustments	Revised purchase equation
Working capital	$ 9,541	$ –	$ 9,541
Property, plant and equipment	142,817	–	142,817
Power purchase and other contracts	87,258	(71,726)	15,532
Goodwill	–	71,726	71,726
Other liabilities	(7,766)	–	(7,766)
Long-term debt	(166,842)	–	(166,842)
Total purchase price	65,008	–	65,008
Less cash acquired	1,617	–	1,617
Cash paid, net of cash acquired	$ 63,391	$ –	$ 63,391

C. PROJECT ACQUISITION

During the year ended December 31, 2005, Atlantic Holdings increased its interest in one of its existing Projects. The fair value of the interest acquired by the Company was $1,074 and was financed by cash consideration at the Project level.

D. ADJUSTMENT OF 2004 ACQUISITION

On November 18, 2004, the Company acquired for total consideration of $522,638 (including $1,014 in acquisition costs) an indirect interest in 15 Projects located primarily in the United States. During the year ended December 31, 2005, the fair value of certain Projects was finalized. The final purchase price allocation is as follows:

	Preliminary purchase equation	Adjustments	Revised purchase equation
Working capital	$ 47,213	$ 577	$ 47,790
Equity investments	142,777	467	143,244
Property, plant and equipment	296,132	6,002	302,134
Other intangible assets	107,340	1,175	108,515
Indexed swap and hedge, net	71,902	–	71,902
Other liabilities	(2,242)	(991)	(3,233)
Long-term debt	(102,476)	(810)	(103,286)
Gas transportation contracts	(38,008)	–	(38,008)
Future tax liability	–	(6,420)	(6,420)
Total purchase price	522,638	–	522,638
Less repayment of assumed debt	167,831	–	167,831
	354,807	–	354,807
Less cash acquired	12,000	–	12,000
	$ 342,807	$ –	$ 342,807
Consideration represented by:			
Cash paid, net of cash acquired	$ 83,725	$ –	$ 83,725
Non-controlling interest liability (note 11)	259,082	–	259,082
	$ 342,807	$ –	$ 342,807

3. Joint venture investments

The Company accounts for eight entities under proportionate consolidation.

Entity	Proportion consolidated
Badger Creek Limited	50.0%
Chambers Cogeneration LP	40.0%
Koma Kulshan Associates	50.0%
Mid-Georgia Cogen LP	50.0%
Orlando Cogen Limited LP	50.0%
Pasco Cogen Ltd.	49.9%
Stockton Cogen Company	50.0%
Topsham Hydro Assets	50.0%

The following summarizes the balance sheets at December 31, 2006 and 2005, and operating results and distributions paid to the Company for the years ended December 31, 2006 and 2005 for the Company's proportionate share of the eight entities:

	Company's share	
	2006	2005
Assets		
Current assets	**$ 56,318**	$ 64,776
Non-current assets	**430,999**	526,761
	$ 487,317	$ 591,537
Liabilities		
Current liabilities	**$ 33,945**	$ 46,940
Non-current liabilities	**177,209**	243,552
	$ 211,154	$ 290,492
Operating results:		
Revenue	**$ 173,484**	$ 126,989
Net income	**19,848**	9,231
Distributions paid to the Company	**$ 31,056**	$ 19,107

4. Property, plant and equipment

	2006	2005
Cost	**$ 450,923**	$ 447,595
Less accumulated depreciation	**39,743**	19,116
	$ 411,180	$ 428,479

Depreciation of $20,627 (2005 – $16,886) was expensed during the year.

5. Equity investments

The Company has an investment in five entities accounted for under the equity method. The entities are Delta-Person Limited Partnership, Gregory Power Partners LP, Jamaica Private Power Limited Company, Rumford Cogeneration Company LP ("Rumford") and Selkirk Cogen Partners LP. The Company owns its interest in Gregory Power Partners LP and a portion of its interest in Rumford through Javelin Energy LLC. On December 28, 2005, the Company sold its interest in Masspower for proceeds of $59,365, realizing a gain on disposition of $5,015. An analysis of the investments is presented below:

		2006		2005
Equity investments, beginning of year (note 2)	**$**	**78,335**	$	139,696
Adjustment to purchase price allocations (note 2)		**–**		467
Disposal of equity investment		**–**		(54,350)
Equity earnings, net		**10,438**		8,446
Distributions received		**(11,800)**		(15,924)
Equity investments, end of year	**$**	**76,973**	$	78,335

The fair value increment on acquisition of the investments has been allocated to property, plant and equipment and other intangible assets.

6. Other intangible assets and transmission system rights

Other intangible assets include power purchase agreements, fuel supply agreements and licenses and rights. Transmission system rights represent the long-term right to approximately 72% of the capacity of the Path 15 transmission line.

		2006		2005
Transmission system rights	**$**	**220,963**	$	–
Power purchase agreements		**110,403**		110,403
Fuel supply agreements		**13,644**		14,832
Licenses and rights		**–**		70,538
		345,010		195,773
Less accumulated amortization		**40,890**		21,096
	$	**304,120**	$	174,677

Amortization of $19,794 (2005 – $19,670) was expensed during the year.

7. Credit facility

The Company has a $75,000 revolving credit facility maturing November 18, 2008, which bears interest at a rate equal to LIBOR or U.S. base rate, plus an applicable margin to those rates. At December 31, 2006, nil (2005 – $10,000) was drawn, and an additional $13,465 (2005 – $15,061) was allocated but not drawn, to support letters of credit. The Company has to meet certain financial covenants. The facility is secured by pledges of assets and interest in certain subsidiaries. In March 2007, the Company borrowed $31,000 under the credit facility and used the proceeds to repay the Acquisition Credit Facility related to the acquisition of Path 15.

8. Long-term debt

	2006	2005
Project debt, interest rates ranging from 3.25% to 9.5%, maturing between 2007 and 2022	**$ 414,374**	$ 246,040
Less current portion of Project debt	**86,168**	21,558
	$ 328,206	$ 224,482

The amount presented in long-term debt above excludes the net unamortized purchase price adjustment of $14,207.

Principal payments due under the terms of short-term and long-term debt in the next five years and thereafter are as follows:

2007	$ 86,168
2008	30,018
2009	21,412
2010	21,800
2011	23,085
Thereafter	231,891
	$ 414,374

The Project debt of joint ventures is secured by the respective facility and its contracts, with no other recourse to the Company. The loans have certain financial covenants that must be met. All of the debt in the table above is represented by non-recourse debt of joint ventures, except for the $51,000 outstanding balance on the Acquisition Credit Facility (see note 2(a)).

Long-term debt represents the Company's consolidated and proportionately consolidated share of the Projects' long-term debt. Project debt is non-recourse to the Company and amortizes during the term of the respective revenue generating contracts of the Projects.

9. Subordinated notes

	2006	2005
Subordinated Notes (Cdn$392,553; 2005 – Cdn$292,207)	**$ 336,840**	$ 251,844

The Company issued $176,560 of 11% Subordinated Notes in conjunction with its initial public offering of IPSs (see note 11) and separately issued $30,367 of 11% Subordinated Notes.

Since the initial public offering, the Company has completed the following additional issuances of 11% Subordinated Notes:

Date	Amount issued	Premium (discount)	Net proceeds
October 2005[1]	$ 37,125	$ 605	$ 37,730
October 2006[1]	43,278	(878)	42,400
December 2006[1]	42,926	(871)	42,055
December 2006[2]	2,597	(53)	2,544

1 Issuance made in connection with IPS offering.
2 Issuance of 11% Subordinated Notes separate from IPSs.

The Subordinated Notes will mature in 2016 subject to redemption under specified conditions at the option of the Company, commencing on or after November 18, 2009. Interest is payable monthly in arrears and the principal repayment will occur at maturity. The Subordinated Notes are denominated in Canadian dollars and are secured by a subordinated pledge of the Company's interest in Atlantic Holdings and certain subsidiaries, and contain certain restrictive covenants.

10. Convertible debentures

On October 11, 2006, the Company closed the sale of Cdn$60,000 aggregate principal amount of convertible secured debentures ("Debentures") for gross proceeds of $52,780. The Debentures pay interest semi-annually on April 30 and October 31 of each year, commencing on April 30, 2007. The Debentures mature on October 31, 2011 and are convertible into approximately 80.6452 IPSs per Cdn$1,000 principal amount of Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per IPS. The Debentures are listed on the Toronto Stock Exchange under the symbol ATP.DB.

11. Non-controlling interest liability

In connection with the Company's initial public offering, the Existing Investors acquired the right to request, at any time, that Atlantic Holdings purchase for cancellation all or any portion of the Existing Investors' interest in Atlantic Holdings, subject to a minimum remaining 10% interest, for a two-year period from November 18, 2004. The repurchase of the Existing Investors' interest is conditional upon Atlantic Holdings being able, utilizing its best efforts, to complete or cause the completion of an equity financing on terms acceptable to those managers of Atlantic Holdings who are independent of the Existing Investors and their affiliates, to secure the necessary funds to enable Atlantic Holdings to purchase the Existing Investors' interest. Atlantic Holdings may only finance repurchases of Existing Investors' interest pursuant to the exercise of the rights by issuing additional equity securities. This may occur through the sale of equity interest to the Company, the purchase of which may be financed by the Company by a sale of IPSs or other equity or debt securities of the Company. This liquidity right is treated as a liability of the Company and is recorded at fair value in the consolidated balance sheets. Any change in the non-controlling interest liability is recognized in the consolidated statements of operations and deficit as a change in non-controlling interest liability.

The Existing Investors have exercised the liquidity right in a series of transactions since the initial public offering through February 2007 as follows:

Date	Amount paid to existing investors	Incremental share[1]
October 2005	$ 64,374	12.0%
October 2006	87,287	15.5%
February 2007	76,888	14.4%

1 Represents the incremental portion of Atlantic Holdings purchased by the Company from the Existing Investors in the transaction.

The amounts paid to the Existing Investors in the transactions above were financed by the Company through the sale of IPSs and Debentures.

12. Common stock

	Number of shares		Amount
Balance, December 31, 2004	36,800	$	121,381
Issuance of common stock	7,539		26,644
Balance, December 31, 2005	44,339		148,025
Issuance of common stock	8,531		36,232
Private placement of common stock	8,600		32,378
Balance, December 31, 2006	61,470	$	216,635

The Company issued 32,000,000 IPSs for cash pursuant to its initial public offering on November 18, 2004 and a further 4,800,000 IPSs on December 6, 2004. Each IPS was issued for Cdn$10.00. Each IPS consists of one common share of the Company and Cdn$5.767 of aggregate principal amount of 11% Subordinated Notes of the Company (see note 9). Proceeds of $121,381, net of offering costs of $7,593), were allocated to common stock.

On October 3, 2005, the Company issued 7,539,000 IPSs at a price of Cdn$10.00 per IPS to Caisse de dépôt et placement du Québec and certain officers of the Company in a secondary private placement. Proceeds of $26,644, (net of offering costs of $64), were allocated to common stock.

On October 6, 2006, the Company issued 8,531,000 IPSs at a price of Cdn$10.55 per IPS. Proceeds of $36,232, net of offering costs, were allocated to common stock.

On December 21, 2006, the Company issued 8,600,000 IPSs at a price of Cdn$10.00 per IPS to Caisse de dépôt et placement du Québec and two other institutional investors. Proceeds of $32,378, net of estimated offering costs, were allocated to common stock.

13. Income taxes

		2006		2005
Current income tax expense	**$**	**577**	$	8,959
Future income tax benefit		**–**		(6,420)
	$	**577**	$	2,539

The table on the following page is a reconciliation of income taxes calculated at the Canadian enacted statutory rate of 36.12% (2005 – 36.12%) to the provision for income taxes in the consolidated statements of operations and deficit:

	2006	2005
Computed income tax expense (recovery) at Canadian statutory rate	$ (662)	$ 733
Increase (decrease) resulting from:		
Operating in countries with different income tax rates	(65)	58
	(727)	791
Valuation allowance	10,103	21,547
	9,376	22,338
Non-taxable foreign-source income	(466)	(904)
Permanent differences	5,287	–
Canadian loss carryforwards	(10,735)	(12,996)
Branch profits tax	546	739
Prior year true-up	(3,588)	(6,420)
Other	157	(218)
	(8,799)	(19,799)
Income tax expense	$ 577	$ 2,539

The tax effect of temporary differences that give rise to significant portions of the future tax assets and future tax liabilities at December 31, 2006 is presented below:

	2006	2005
Future tax assets:		
Intangible assets	$ 57,697	$ 8,849
Loss carryforwards	23,594	12,996
Gas transportation contract and other accrued liabilities	16,090	13,321
Unrealized foreign exchange loss on Subordinated Notes	570	3,427
IPS issuance costs	4,372	–
Other	744	2,702
Total future tax assets	103,067	41,295
Valuation allowance	(61,602)	(21,904)
	41,465	19,391
Future tax liabilities:		
Property, plant and equipment	57,012	15,682
IPS issuance costs	–	–
Unrealized foreign exchange gain	1,554	2,858
Other	–	851
Total future tax liabilities	58,566	19,391
Net future tax liability	$ (17,101)	$ –

As of December 31, 2006, the Company had the following net operating loss carryforwards, scheduled to expire in the following years:

2014	$	5,504
2015		30,476
2026		28,144
	$	64,124

These losses relate to the Canadian entity and may be used only to offset the future income of the Canadian entity for Canadian income tax purposes. A full valuation allowance was taken against the future tax assets set up in respect of the Canadian entity's loss carryforwards as the Company believes that it is not more likely than not that the Canadian entity will be able to use any of these loss carryforwards.

14. Commitments and contingencies

A. From time to time, the Company and its subsidiaries and the Projects are parties to disputes and litigation that arise in the normal course of business. The Company assesses its exposure to these matters and records estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of December 31, 2006 that are expected to have a material impact on the Company's financial position or results of operations.

(1) The Chambers partnership, in which Atlantic Holdings owns a 40% indirect interest, filed suit against its coal supplier, Consol Pennsylvania Coal Company and related entities, over a disagreement involving the pricing of a portion of the annual coal deliveries to the plant. Chambers was seeking, among other things; (i) a declaratory judgment regarding the terms of the agreement; (ii) damages for missed deliveries; and (iii) injunctive relief to ensure delivery of all coal requested under the contract. The coal supplier had asserted affirmative defenses and counterclaims in its answer. In the third quarter of 2006, a settlement agreement was reached, subject to final documentation. The terms of the proposed settlement do not have a material impact on the financial position or results of operations of the Project.

(2) Rumford purchases its coal from Massey Coal Sales Company ("Massey"). Massey's coal is delivered through a Sprague Energy Corp. ("Sprague") marine terminal. Massey and Sprague had disputed terms and compensation for certain terminal services provided by Sprague and Massey had asserted that Rumford also had failed to pay certain amounts due under the coal supply agreement. In the third quarter of 2006, the dispute was settled for an amount that was not material to the project.

B. Certain Projects have long-term contracts for supply and transportation of fuel. The contracts may have minimum volumetric commitments for delivery, but these obligations are non-recourse to the Company.

C. Certain Projects provide letters of credit ("LOCs") to power purchase agreement buyers for contingent project obligations. The Company's aggregate share of these LOCs was $13,465 at December 31, 2006 (2005 – $15,061), supported by the Company's revolving credit facility.

15. Indexed swap

A swap agreement (the "Indexed Swap") between a utility company and Onondaga has replaced the Projects' original power purchase contract. The Indexed Swap expires on June 30, 2008. The Indexed Swap is a financial instrument under which the utility company makes monthly payments to Onondaga based on the difference between an indexed "contract price" and a market reference price for electricity. The indexed contract price fluctuates in relation to the market price of natural gas and a prescribed index of inflation. The notional quantity of electricity for the purpose of these calculations is fixed for the full term of the Indexed Swap.

In May 2004, Onondaga contributed the Indexed Swap to a newly formed wholly owned special purpose subsidiary, Onondaga Power Swap Holdings, LLC ("OPSH"). Onondaga has guaranteed OPSH's obligations to the utility company under the Indexed Swap. Also in May 2004, OPSH entered into commodity hedges (the "Indexed Swap Hedge") in order to lock in favourable gas, power and capacity pricing under the Indexed Swap. The hedges extend through June 30, 2008 and remove almost all commodity exposure from the Indexed Swap during its term.

Changes related to the Indexed Swap are summarized below:

	2006	2005
Fair value as of December 31, 2005	**$ 107,914**	$ 99,591
Increase (decrease) in fair value	**(25,432)**	46,818
Settlements received	**(32,358)**	(38,495)
Fair value as of December 31, 2006	**$ 50,124**	$ 107,914

Changes related to the Indexed Swap Hedge:

	2006	2005
Fair value as of December 31, 2005	**$ (58,547)**	$ (30,293)
Decrease (increase) in fair value	**29,941**	(40,479)
Settlements received	**9,617**	12,225
Fair value as of December 31, 2006	**$ (18,989)**	$ (58,547)

16. Related party transactions

The Company has contracted with Atlantic Power Management, LLC (the "Manager"), a company owned by certain entities that form part of the non-controlling interest (see note 11), for management services, including business planning, asset management, acquisitions, financial reporting and general management services. The Manager receives an annual management fee of $340, cost reimbursements and an incentive fee equal to approximately 25% of aggregate cash distributions in excess of Cdn$1.00 per IPS and Existing Investor interest. In 2006, the Manager was paid $3,899 (2005 – $2,989).

The Company has engaged Caithness Energy, a company affiliated with the non-controlling interest, to provide operations and maintenance at four of the Projects and accounting, tax and other administrative functions for certain of the Projects. In 2006, Caithness Energy was paid $2,750 (2005 – $2,750).

17. Fair values of financial instruments

The fair values of cash and cash equivalents, restricted cash, accounts receivable, dividends payable, and accounts payable and accrued liabilities approximate carrying values due to the short-term nature of these balances.

The Indexed Swap and Indexed Swap Hedge agreements (see note 15) are recorded at their estimated fair values based on estimated future cash flows, taking into account certain assumptions, including forecasts of future energy prices, inflation rates, discount rates and credit risk. Energy prices can be volatile and other assumptions can change from period to period. These factors can create significant fluctuations in the estimated fair values of these agreements.

Non-controlling interest are carried at estimated fair value. Prior to December 31, 2006, fair value was estimated based on the number of IPSs that would be issued to extinguish the liability multiplied by the market price of the IPSs at the end of the period. At December 31, 2006, the fair value was estimated as the actual amount paid to the Existing Investors in February 2007 to extinguish the liability.

Foreign exchange forward contracts are carried at estimated fair value based on quoted market value.

The fair value of long-term debt approximates its carrying value based on discounting of cash flows at current market rates.

The fair value of derivative financial instruments is as follows:

	Fair value		Carrying value	
	2006	2005	**2006**	2005
Indexed Swap	**$ 50,124**	$ 107,914	**$ 50,124**	$ 107,914
Indexed Swap Hedge	**(18,989)**	(58,547)	**(18,989)**	(58,547)
Forward foreign currency contract[2]	**3,886**	10,212	**3,886**	1,827
Interest rate swap liabilities[1,3]	**(4,402)**	(6,171)	**(4,402)**	(6,171)
Natural gas swap assets[1,2]	**–**	3,183	**–**	–

1 Represents the Company's proportionate share of joint venture investments.
2 Included in other assets in the consolidated balance sheets.
3 Included in other liabilities in the consolidated balance sheets.

The Company uses forward foreign currency contracts to manage its exposure to changes in foreign exchange rates, as the Company earns its income principally in the United States and has the obligation to make distributions predominantly in Canadian dollars. Since its inception, the Company has established a hedging strategy for the purpose of reinforcing the long-term sustainability of its distributions. The Company has executed this strategy by entering into forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make monthly distributions through December 2011 at the current annual distribution level of Cdn$1.06 per IPS to all holders, including the Existing Investors, as well as interest payments on the Subordinated Notes.

The following table summarizes the monthly settlement terms of the Company's forward foreign currency contracts as of December 31, 2006:

Notional monthly amounts

Date	Sell U.S. dollars	Buy Canadian dollars	Average rate
Current–2009	4,811	5,800	1.2055
2010	5,167	5,800	1.1225
2011	5,494	5,800	1.0557

In addition to the forward contracts that settle on a monthly basis, the Company has executed forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make semi-annual payments on the Debentures. The contracts provide for the purchase of Cdn$2.1 million and Cdn$1.9 million in April 2007 and October 2007, respectively, at a rate of 1.1240 Canadian dollar per U.S. dollar, and the purchase of Cdn$1.9 million in April and October 2008 through 2011 at a rate of 1.1075 Canadian dollar per U.S. dollar.

18. Basic and diluted loss per share

Basic loss per share has been calculated using the weighted average number of units outstanding during the year of 46,398,368 (2005 – 38,659,055).

Diluted loss per share is computed by assuming that the Debentures are converted into 4,838,712 IPSs for the period during 2006 when the Debentures were outstanding.

19. Segmented information

The Company owns investments in 15 Projects in the United States, as well as one Project in Jamaica, which is accounted for using the equity method.

The Company has one line of business: investment in projects engaged in the business of generating and transmitting electricity.

Revenue is earned primarily from contracts with large investor-owned utilities. Two investment-grade utilities contributed more than 10% of revenue in each of the years ended December 31, 2006 and 2005, as follows:

	Percent of total revenue	
	2006	2005
Utility A	47%	58%
Utility B	17%	20%

20. Comparative figures

Certain 2005 figures have been reclassified to conform with the financial statement presentation adopted in 2006.

CORPORATE INFORMATION

Atlantic Power Management

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PRESIDENT AND CHIEF EXECUTIVE OFFICER

Patrick Welch
CHIEF FINANCIAL OFFICER AND CORPORATE SECRETARY

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Atlantic Power Corporation

Exchange Listing
IPSs Issued and Outstanding: 61,470,500
Ticker Symbol: ATP.UN

Cdn$60 million 6.25% Convertible Debentures due Oct. 31, 2011
Ticker Symbol: ATP.DB

Exchange: TSX

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Annual Meeting
Wednesday, June 6, 2007, 10:00 a.m. ET
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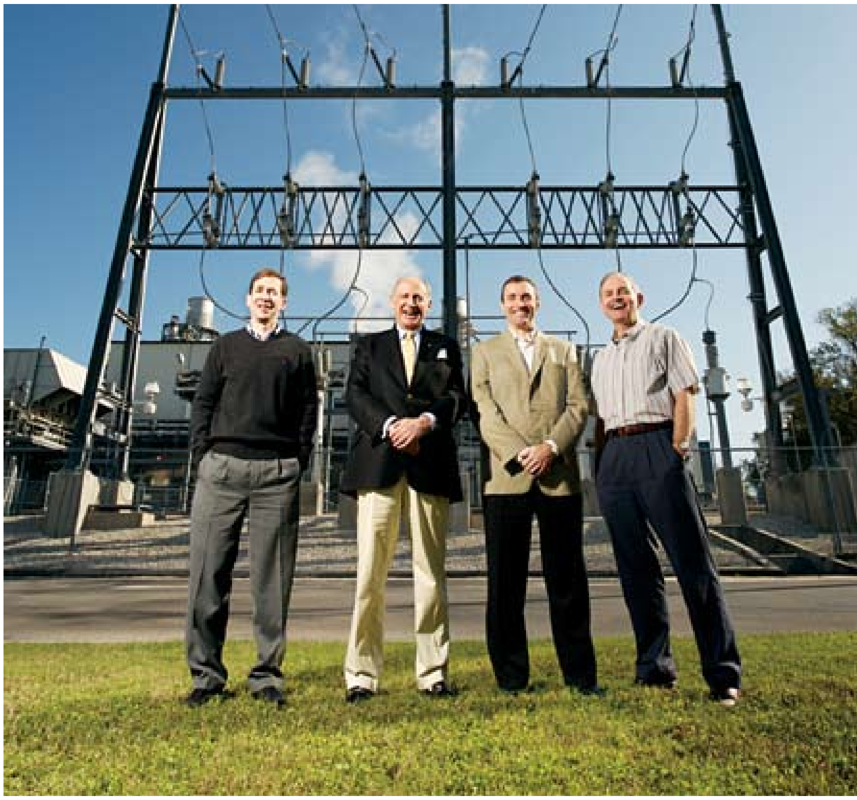
Atlantic Power Corporation Directors

Irving Gerstein
CHAIRMAN OF THE BOARD
Toronto, Ontario
Mr. Gerstein is a retired executive and is currently a Director of Medical Facilities Corporation, Economic Investment Trust Limited and Student Transportation of America.

Ken Hartwick
CHAIRMAN OF THE AUDIT COMMITTEE
Toronto, Ontario
Mr. Hartwick is currently the President of Ontario Energy Savings Corp., which is a wholly owned subsidiary of, and provides administrative services to, Energy Savings Income Fund, an income trust traded on the TSX.

John McNeil
Toronto, Ontario
Mr. McNeil is President of BDR NorthAmerica Inc. based in Toronto, Ontario, an energy consulting firm.

Bill Whitman
Ridgewood, New Jersey
Mr. Whitman is currently the Senior Vice President of NW Financial Group, LLC, Jersey City, NJ, an investment bank specializing in municipal finance.



From left to right: Bill Whitman, Irving Gerstein, Ken Hartwick and John McNeil at the Pasco Project in Dade City, Florida.

DESIGN: ATLANTA VISUAL COMMUNICATIONS

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