FINANCIAL FEDERAL CORP
Form 10-Q
June 07, 2007

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

FORM 10-Q

|X| QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended April 30, 2007

OR

|_| TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______ to _______

Commission file number 1-12006

FINANCIAL FEDERAL CORPORATION
(Exact name of Registrant as specified in its charter)

| Nevada | 88-0244792 |
|---|---|
| (State of incorporation) | (I.R.S. Employer Identification No.) |

733 Third Avenue, New York, New York 10017
(Address of principal executive offices)

Registrant's telephone number, including area code (212) 599-8000

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes |X| No |_|

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one)

Large accelerated filer |X| Accelerated filer |_| Non-accelerated filer |_|

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes |_| No |X|

The number of shares outstanding of the registrant's common stock on June 1, 2007 was 25,780,060.

FINANCIAL FEDERAL CORPORATION AND SUBSIDIARIES

Quarterly Report on Form 10-Q

for the quarter ended April 30, 2007

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements

FINANCIAL FEDERAL CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands, except par value)

| | April 30, 2007* | July 31, 2006 |
|---|---|---|

| | | |
|---|---|---|
| ASSETS | | |
| Finance receivables | $2,097,937 | $1,991,688 |
| Allowance for credit losses | (24,115) | (24,100) |
| Finance receivables - net | 2,073,822 | 1,967,588 |
| Cash | 12,724 | 8,143 |
| Other assets | 9,617 | 12,613 |
| TOTAL ASSETS | $2,096,163 | $1,988,344 |
| LIABILITIES | | |
| Debt: | | |
| Long-term ($4,400 at April 30, 2007 and $5,700 at July 31, 2006 owed to related parties) | $1,356,200 | $1,252,350 |
| Short-term | 276,500 | 275,311 |
| Accrued interest, taxes and other liabilities | 80,526 | 70,304 |
| Total liabilities | 1,713,226 | 1,597,965 |
| STOCKHOLDERS' EQUITY | | |
| Preferred stock - $1 par value, authorized 5,000 shares | -- | -- |
| Common stock - $.50 par value, authorized 100,000 shares, shares issued and outstanding (net of 1,696 treasury shares): 25,932 at April 30, 2007 and 27,216 at July 31, 2006 | 12,966 | 13,608 |
| Additional paid-in capital | 125,685 | 123,091 |
| Retained earnings | 243,164 | 253,128 |
| Accumulated other comprehensive income | 1,122 | 552 |
| Total stockholders' equity | 382,937 | 390,379 |
| TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY | $2,096,163 | $1,988,344 |

* Unaudited

See accompanying notes to consolidated financial statements

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FINANCIAL FEDERAL CORPORATION AND SUBSIDIARIES

CONSOLIDATED INCOME STATEMENTS *
(In thousands, except per share amounts)

| | Three Months Ended April 30, | | Nine Months Ended April 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Finance income | $47,490 | $41,429 | $141,803 | $117,420 |
| Interest expense | 20,541 | 17,172 | 62,506 | 47,463 |
| Net finance income before provision for credit | | | | |

| | | | | |
|---|---|---|---|---|
| losses on finance receivables | 26,949 | 24,257 | 79,297 | 69,957 |
| Provision for credit losses on finance receivables | -- | -- | -- | -- |
| Net finance income | 26,949 | 24,257 | 79,297 | 69,957 |
| Salaries and other expenses | 6,243 | 5,957 | 18,494 | 17,216 |
| Income before provision for income taxes | 20,706 | 18,300 | 60,803 | 52,741 |
| Provision for income taxes | 7,996 | 7,148 | 23,468 | 20,616 |
| NET INCOME | $12,710 | $11,152 | $ 37,335 | $ 32,125 |
| EARNINGS PER COMMON SHARE: | | | | |
| Diluted | $ 0.48 | $ 0.42 | $ 1.40 | $ 1.22 |
| Basic | $ 0.49 | $ 0.43 | $ 1.43 | $ 1.24 |

* Unaudited

See accompanying notes to consolidated financial statements



FINANCIAL FEDERAL CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY *
(In thousands)

| | Common Stock Shares | Common Stock Amount | Additional Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income | |
|---|---|---|---|---|---|---|
| BALANCE - JULY 31, 2005 | 26,231 | $13,116 | $109,226 | $219,772 | $ -- | $3 |
| Net income | -- | -- | -- | 32,125 | -- | |
| Unrealized gain on cash flow hedge, net of tax | -- | -- | -- | -- | 583 | |
| Reclassification adjustment for realized gain included in net income, net of tax | -- | -- | -- | -- | (10) | |
| Comprehensive income | | | | | | |
| Common stock repurchased (retired) | (25) | (13) | (475) | (246) | -- | |
| Stock plan activity: | | | | | | |
| Shares issued | 929 | 465 | 4,907 | (52) | -- | |
| Compensation recognized | -- | -- | 4,285 | -- | -- | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Excess tax benefits | -- | -- | 1,582 | -- | -- | |
| Common stock cash dividends | -- | -- | -- | (7,129) | -- | |
| Cash paid for fractional shares | (4) | (2) | -- | (107) | -- | |
| BALANCE - APRIL 30, 2006 | 27,131 | $13,566 | $119,525 | $244,363 | $ 573 | $3 |

| | Common Stock | | Additional Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income | |
|---|---|---|---|---|---|---|
| | Shares | Amount | | | | |
| BALANCE - JULY 31, 2006 | 27,216 | $13,608 | $123,091 | $253,128 | $ 552 | $3 |
| Net income | -- | -- | -- | 37,335 | -- | |
| Unrealized gain on cash flow hedge, net of tax | -- | -- | -- | -- | 720 | |
| Reclassification adjustment for realized gain included in net income, net of tax | -- | -- | -- | -- | (150) | |
| Comprehensive income | | | | | | |
| Common stock repurchased (retired) | (1,710) | (855) | (8,625) | (36,372) | -- | ( |
| Stock plan activity: | | | | | | |
| Shares issued | 435 | 217 | 5,082 | -- | -- | |
| Shares canceled | (9) | (4) | 4 | -- | -- | |
| Compensation recognized | -- | -- | 5,031 | -- | -- | |
| Excess tax benefits | -- | -- | 1,102 | -- | -- | |
| Common stock cash dividends | -- | -- | -- | (10,927) | -- | ( |
| BALANCE - APRIL 30, 2007 | 25,932 | $12,966 | $125,685 | $243,164 | $1,122 | $3 |

* Unaudited

See accompanying notes to consolidated financial statements



FINANCIAL FEDERAL CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS *
(In thousands)

| Nine Months Ended April 30, | 2007 | 2006 |
|---|---|---|
| Cash flows from operating activities: | | |
| Net income | $ 37,335 | $ 32,125 |

| | | |
|---|---|---|
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Amortization of deferred origination costs and fees | 11,961 | 10,965 |
| Stock-based compensation | 2,892 | 2,235 |
| Depreciation and amortization | 393 | 629 |
| Decrease in other assets | 2,453 | 1,500 |
| Increase in accrued interest, taxes and other liabilities | 13,369 | 6,358 |
| Excess tax benefits from stock-based awards | (1,102) | (1,582) |
| Net cash provided by operating activities | 67,301 | 52,230 |
| Cash flows from investing activities: | | |
| Finance receivables originated | (911,373) | (1,008,230) |
| Finance receivables collected | 795,317 | 743,518 |
| Net cash used in investing activities | (116,056) | (264,712) |
| Cash flows from financing activities: | | |
| Commercial paper, net increase | 171,072 | 45,099 |
| Bank borrowings, net decrease | (126,033) | (47,065) |
| Asset securitization (repayments) borrowings | (42,500) | 100,000 |
| Proceeds from term notes | 125,000 | 150,000 |
| Repayments of term notes | (25,000) | (32,500) |
| Proceeds from settlement of interest rate locks | 1,175 | 970 |
| Proceeds from stock option exercises | 5,254 | 5,320 |
| Excess tax benefits from stock-based awards | 1,102 | 1,582 |
| Common stock issued | 45 | -- |
| Common stock repurchased | (45,852) | (734) |
| Common stock cash dividends | (10,927) | (7,129) |
| Cash paid for fractional shares of common stock | -- | (109) |
| Net cash provided by financing activities | 53,336 | 215,434 |
| NET INCREASE IN CASH | 4,581 | 2,952 |
| Cash - beginning of period | 8,143 | 8,456 |
| CASH - END OF PERIOD | $ 12,724 | $ 11,408 |

* Unaudited

See accompanying notes to consolidated financial statements

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FINANCIAL FEDERAL CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except per share amounts)
(Unaudited)

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Business

Financial Federal Corporation and subsidiaries (the "Company") provide collateralized lending, financing and leasing services nationwide to small and medium sized businesses in the general construction, road and infrastructure construction and repair, road transportation and waste disposal industries. We lend against, finance and lease a wide range of new and used revenue-producing, essential-use equipment including cranes, earthmovers, personnel lifts, trailers and trucks.

Basis of Presentation and Principles of Consolidation

We prepared the accompanying unaudited Consolidated Financial Statements according to the Securities and Exchange Commission's rules and regulations. These rules and regulations permit condensing or omitting certain information and note disclosures normally included in financial statements prepared according to accounting principles generally accepted in the United States of America (GAAP). The July 31, 2006 Consolidated Balance Sheet was derived from audited financial statements but does not include all disclosures required by GAAP. However, we believe the disclosures are sufficient to make the information presented not misleading. These Consolidated Financial Statements and accompanying notes should be read with the Consolidated Financial Statements and accompanying notes included in our Annual Report on Form 10-K for the fiscal year ended July 31, 2006.

In our opinion, the Consolidated Financial Statements include all adjustments (consisting of only normal recurring items) necessary to present fairly our financial position and results of operations for the periods presented. The results of operations for the three and nine months ended April 30, 2007 may not be indicative of full year results.

We split our common stock 3-for-2 in the form of a stock dividend in January 2006. All share and per share amounts (including stock options, restricted stock and stock units), excluding treasury stock, in the Consolidated Financial Statements and accompanying notes were restated to reflect the split. We did not split treasury shares.

Use of Estimates

GAAP requires us to make significant estimates and assumptions affecting the amounts reported in the Consolidated Financial Statements and accompanying notes for the allowance for credit losses, non-performing assets, residual values and stock-based compensation. Actual results could differ from these estimates significantly.

New Accounting Standards

The Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - An Interpretation of FASB 109", ("FIN No. 48") in July 2006. FIN No. 48 requires companies to determine if any tax positions taken on their income tax returns lowering the amount of tax currently due would more likely than not be allowed by a taxing jurisdiction. If tax positions pass the more-likely-than-not test, companies then record benefits from them only equal to the highest amount having a greater than 50% chance of being realized assuming the tax positions would be challenged by a taxing jurisdiction. No benefits would be recorded for tax positions failing the more-likely-than-not test. Tax benefits include income tax savings and the related interest expense savings. Whether tax positions pass the test or not, adopting FIN No. 48 could result in additional income tax provisions or expenses for any interest and penalties on potential underpayments of income tax, or both. FIN No. 48 is effective in the first quarter of fiscal years beginning after December 15, 2006. It will become effective for us on August 1, 2007, the beginning of our fiscal year ending July 31, 2008. We are evaluating how it may affect our consolidated financial statements.

The FASB issued Statement of Financial Accounting Standards ("SFAS") No. 157, "Fair Value Measurements", ("SFAS No. 157") in September 2006. SFAS No. 157

defines fair value (replacing all prior definitions) and creates a framework to measure fair value, but does not create any new fair value measurements. SFAS No. 157 is effective in the first quarter of fiscal years beginning after November 15, 2007. It will become effective for us on August 1, 2008. We are evaluating how it may affect our consolidated financial statements.

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The FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - Including an amendment of FASB Statement No. 115" in February 2007. SFAS No. 159 permits companies to choose to measure many financial instruments and certain other items at fair value at specified election dates and to report unrealized gains and losses on these items in earnings at each subsequent reporting date. SFAS No. 159 is effective in the first quarter of fiscal years beginning after November 15, 2007. It will become effective for us on August 1, 2008. We are evaluating how it may affect our consolidated financial statements.

NOTE 2 - FINANCE RECEIVABLES

Finance receivables comprise installment sale agreements and secured loans (including line of credit arrangements), collectively referred to as loans, with fixed or floating (indexed to the prime rate) interest rates, and direct financing leases as follows:

| | April 30, 2007 | July 31, 2006 |
|---|---|---|
| Loans: | | |
| Fixed rate | $1,726,556 | $1,662,805 |
| Floating rate | 167,595 | 131,235 |
| Total loans | 1,894,151 | 1,794,040 |
| Direct financing leases * | 203,786 | 197,648 |
| Finance receivables | $2,097,937 | $1,991,688 |

* includes residual values of $42,400 at April 30, 2007 and $41,200 at July 31, 2006

Line of credit arrangements contain off-balance sheet risk and are subject to the same credit policies and procedures as other finance receivables. The unused portion of these commitments was $33,800 at April 30, 2007 and $23,800 at July 31, 2006.

The allowance for credit losses activity is summarized below:

| | Three Months Ended April 30, | | Nine Months Ended April 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Allowance - beginning of period | $24,148 | $24,116 | $24,100 | $24,225 |
| Provision | -- | -- | -- | -- |
| Write-downs | (775) | (1,046) | (1,925) | (2,901) |

| | | | | |
|---|---|---|---|---|
| Recoveries | 742 | 957 | 1,940 | 2,703 |
| Allowance - end of period | $24,115 | $24,027 | $24,115 | $24,027 |
| Percentage of finance receivables | 1.15% | 1.25% | 1.15% | 1.25% |
| Net charge-offs (recoveries) * | $ 33 | $ 89 | $ (15) | $ 198 |
| Loss ratio ** | 0.01% | 0.02% | --% | 0.01% |

* write-downs less recoveries
** net charge-offs over average finance receivables, annualized

Non-performing assets comprise finance receivables classified as non-accrual (income recognition has been suspended and the receivables are considered impaired) and assets received to satisfy finance receivables (repossessed equipment, included in other assets) as follows:

| | April 30, 2007 | July 31, 2006 |
|---|---|---|
| Finance receivables classified as non-accrual | $15,934 | $13,750 |
| Assets received to satisfy finance receivables | 2,090 | 809 |
| Non-performing assets | $18,024 | $14,559 |



The allowance for credit losses included $200 at April 30, 2007 and $300 at July 31, 2006 specifically allocated to $4,300 and $4,200 of impaired finance receivables, respectively. We did not recognize any income in the nine months ended April 30, 2007 or 2006 on impaired loans before collecting our net investment.

NOTE 3 - DEBT

Debt is summarized below:

| | April 30, 2007 | July 31, 2006 |
|---|---|---|
| Fixed rate term notes: | | |
| 5.00% due 2010 - 2011 | $ 250,000 | $ 250,000 |
| 5.45% - 5.57% due 2011 - 2014 | 325,000 | 200,000 |
| 5.92% - 6.80% due 2007 - 2008 | 36,250 | 61,250 |
| Total fixed rate term notes | 611,250 | 511,250 |
| Fixed rate term notes swapped to floating rates due 2008 - 2010 | 143,250 | 143,250 |
| Floating rate term note | -- | 10,000 |
| 2.0% convertible debentures due 2034 | 175,000 | 175,000 |
| Total term debt | 929,500 | 839,500 |
| Asset securitization financings | 382,500 | 425,000 |
| Commercial paper | 289,911 | 118,839 |

| | | |
|---|---|---|
| Bank borrowings | 33,689 | 149,722 |
| Total principal | 1,635,600 | 1,533,061 |
| Fair value adjustment of hedged debt | (2,900) | (5,400) |
| Total debt | $1,632,700 | $1,527,661 |

Term Notes

We issued $125,000 of fixed rate term notes in April 2007. The notes comprise $75,000 of five-year, 5.48% notes and $50,000 of seven-year, 5.57% notes due at maturity in April 2012 and 2014. We will pay interest semiannually.

We repaid $25,000 of 5.92% fixed rate term notes at maturity and we converted a $10,000 floating rate term note from a bank due in fiscal 2008 to a $15,000 three-year committed unsecured revolving credit facility in the first nine months of fiscal 2007.

Convertible Debentures

We irrevocably elected (under the original terms of the debentures and without modifying the debentures) in fiscal 2005 to pay the value of converted debentures, not exceeding the principal amount, in cash instead of issuing shares of our common stock. As a result, the 6,169,000 convertible shares are no longer issuable upon conversion but we would need to pay any value over principal by issuing shares of common stock and the value of the debentures is still determined by the number of convertible shares. The value of converted debentures would exceed the principal amount when the price of our common stock exceeds the conversion price. Shares needed to pay the value over principal would equal the difference between the conversion date price of our common stock and the conversion price, divided by the conversion date price and multiplied by the number of convertible shares. No event allowing for the debentures to be converted has occurred through April 30, 2007.

The conversion rate increased in the first nine months of fiscal 2007 because we declared cash dividends on our common stock. At April 30, 2007, the conversion rate was 35.25 (number of convertible shares for each $1 (one thousand) of principal), the conversion price was $28.37 and we would have to deliver the value of 6,169,000 shares of our common stock upon conversion of all the debentures. The conversion rate, conversion price and number of convertible shares at July 31, 2006 were 34.75, $28.78 and 6,081,000, respectively. Future cash dividends will cause additional conversion rate and convertible shares increases and conversion price decreases.



Asset Securitization Financings

We have a $425,000 asset securitization facility providing committed revolving financing through April 2008. The facility was renewed in April 2007. If the facility is not renewed again, we could convert borrowings outstanding into term debt. The term debt would be repaid monthly based on the amount of securitized receivables and would be fully repaid by December 2009. Finance receivables include $478,000 and $487,000 of securitized receivables at April 30, 2007 and July 31, 2006, respectively. We can securitize an additional $357,000 of finance receivables at April 30, 2007. Borrowings are limited to 94% of securitized receivables and can be further limited based on the eligibility of securitized receivables. We repaid $42,500 of borrowings under this facility in April 2007 with proceeds from our term note issuance.

Bank Borrowings

We have $530,000 of committed unsecured revolving credit facilities from ten banks expiring as follows; $80,000 within one year and $450,000 between September 2008 and October 2012.

Other

Our major operating subsidiary's debt agreements have restrictive covenants including limits on its indebtedness, encumbrances, investments, dividends and other distributions to us, sales of assets, mergers and other business combinations, capital expenditures, interest coverage and net worth. We were in compliance with all debt covenants at April 30, 2007. None of the agreements have a material adverse change clause. All of our debt is senior.

Long-term debt comprised the following:

| | April 30, 2007 | July 31, 2006 |
|---|---|---|
| Term notes | $ 635,600 | $ 602,850 |
| Bank borrowings and commercial paper supported by bank credit facilities expiring after one year | 323,600 | 247,500 |
| Asset securitization financings | 222,000 | 227,000 |
| Convertible debentures | 175,000 | 175,000 |
| Total long-term debt | $1,356,200 | $1,252,350 |

NOTE 4 - DERIVATIVES

We entered into interest rate locks with a total notional amount of $100,000 with three banks in September 2006. The rate locks had a March 2007 expiration. We designated the rate locks as cash flow hedges of our anticipated issuance of fixed rate term notes hedging the risk of higher interest payments on the notes for the first five years from increases in market interest rates before the notes were issued. We terminated the rate locks in January 2007 and realized a $1,006 gain.

We entered into another interest rate lock with a notional amount of $50,000 with a bank in March 2007 with an April 2007 expiration. We designated it as a cash flow hedge of the same anticipated fixed rate term notes issuance originally hedged in September 2006. We terminated this rate lock in April 2007 when the hedged notes were issued and we realized a $169 gain. The four rate locks were determined to be highly effective.

The amount of the gains on these four rate locks relating to hedge ineffectiveness was $100. We recorded this amount as a reduction of interest expense in the three and nine months ended April 30, 2007. We recorded the $1,075 effective amount of the gains in stockholders' equity as accumulated other comprehensive income net of deferred income tax of $417. We are reclassifying this after-tax amount into net income over five years by reducing interest expense and deferred income tax. These rate locks effectively lowered the interest rate on the fixed rate notes issued in April 2007 by 0.20% (20 basis points).

We also have fixed to floating interest rate swaps with a total notional amount of $143,250 at April 30, 2007 and July 31, 2006. The swaps effectively converted fixed rate term notes into floating rate term notes. We designated the swaps as fair value hedges of fixed rate term notes. The swaps expire on the notes' maturity dates. Semiannually, we receive fixed amounts from the swap counterparty banks equal to the interest we pay on the hedged fixed rate notes, and we pay amounts to the swap counterparty banks equal to the swaps' floating rates multiplied by the swaps' notional amounts. We record the differences between these amounts in interest expense. The swaps' floating rates change semiannually to a fixed amount over six-month LIBOR. We receive a weighted-average fixed rate of 4.88% and the weighted-average floating pay rate



was 6.89% at April 30, 2007 and July 31, 2006. The fair value of the swaps was a liability of $2,900 at April 30, 2007 and $5,400 at July 31, 2006.

NOTE 5 - STOCKHOLDERS' EQUITY

We increased the amount available under our common stock and convertible debt repurchase program by $32,617 and we repurchased 1,693,000 shares of our common stock for $45,385 paying a weighted-average price of $26.80 per share in the third quarter of fiscal 2007. We also received 17,500 shares of common stock from employees in the first nine months of fiscal 2007 at a weighted-average price of $26.70 per share for payment of income tax we were required to withhold on vested shares of restricted stock. We retired all shares repurchased and received in fiscal 2007. We completed the program in May 2007 with the repurchase of 159,000 shares for $4,300 paying a $27.00 weighted-average price per share.

We paid quarterly cash dividends totaling $0.40 per share of common stock in the first nine months of fiscal 2007. We declared a quarterly cash dividend of $0.15 per share of common stock in June 2007 payable in July 2007.

NOTE 6 - STOCK PLANS

Our stockholders approved two stock plans in December 2006; the 2006 Stock Incentive Plan (the "2006 Plan") and the Amended and Restated 2001 Management Incentive Plan (the "Amended MIP"). The 2006 Plan provides for the issuance of 2,500,000 incentive or non-qualified stock options, shares of restricted stock, stock appreciation rights, stock units and common stock to officers, other employees and directors subject to annual participant limits, and expires in December 2016. Awards may be subject to performance goals. The 2006 Plan replaced the 1998 Stock Option/Restricted Stock Plan (the "1998 Plan"). The 1998 Plan terminated upon approval of the 2006 Plan. The exercise price of incentive stock options granted under these plans can not be less than the fair market value of our common stock when granted and the term of incentive stock options is limited to ten years. There were 2,229,000 shares available for future grants under the 2006 Plan at April 30, 2007. The Amended MIP provides for the issuance of 1,000,000 shares of restricted stock, with an annual participant limit of 200,000 shares, and cash or stock bonuses to be awarded to our CEO and other selected officers subject to predetermined performance goals. The Amended MIP expires in December 2011. There were 750,000 shares available for future grants under the Amended MIP at April 30, 2007.

The 1998 Plan was amended in December 2005 according to its anti-dilution provisions to increase the number of shares available for the January 2006 stock split. The 1998 Plan provided for the issuance of 3,750,000 incentive or non-qualified stock options or shares of restricted stock to officers, other employees and directors. None of the options or shares of restricted stock awarded under the 1998 Plan are performance based.

Options granted through the first half of fiscal 2005 were mostly incentive stock options with a six-year term vesting 25% after two, three, four and five years. Options granted in the second half of fiscal 2005 were non-qualified options with a four-year term vesting 33 1/3% on July 31, 2005, 2006 and 2007. Options granted after fiscal 2005 were non-qualified options with a five-year term vesting 25% after one, two, three and four years. We granted 131,000 non-qualified stock options to employees in February 2007.

Shares of restricted stock awarded (excluding 435,000 shares awarded to executive officers in February 2006) vest annually in equal amounts over original periods of three to eight years (seven year weighted-average). Shares of restricted stock awarded to executive officers in February 2006 vest when the officer's service terminates, other than upon a non-qualifying termination, after six months (i) after the executive officer attains age 62 or (ii) after August 2026 if earlier (twelve year weighted-average). We awarded 120,000 shares of restricted stock to employees in February 2007.

We awarded 19,000 restricted stock units to non-employee directors in January 2007. The units vest in one year or earlier upon the sale of the Company or the director's death or disability, and are subject to forfeiture. Each unit represents the right to receive one share of common stock and the units earn dividend equivalents to be paid in additional shares of common stock. Vested units will convert into shares of common stock when a director's service terminates. We also issued 1,500 shares of common stock as payment of annual director retainer fees. The price of our common stock on the date we issued these shares was $28.73.



The Management Incentive Plan ("MIP") for our Chief Executive Officer ("CEO") was approved by stockholders in fiscal 2002. We amended it in December 2005 according to its anti-dilution provisions to increase the number of shares for the January 2006 stock split. We awarded 41,000 shares of restricted stock to our CEO in November 2005 as part of the fiscal 2006 bonus subject to certain performance conditions. Shares earned vest annually in equal amounts over four years. Our CEO earned 36,000 of these shares in September 2006 and forfeited 5,000 shares based on our fiscal 2006 performance. Our CEO earned 27,000 shares of restricted stock in September 2005 vesting annually in equal amounts over four years as a bonus for fiscal 2005. Our CEO earned 15,000 shares of restricted stock in fiscal 2005 vesting annually in equal amounts over five years as part of the fiscal 2004 bonus. No shares were awarded for fiscal 2007. At April 30, 2007, 103,000 shares of our CEO's restricted stock awarded under the MIP were unvested and are scheduled to vest within four years.

We established a Supplemental Retirement Benefit ("SERP") for our CEO in fiscal 2002. We amended it in December 2005 according to its anti-dilution provisions to increase the number of units for the January 2006 stock split, and we amended it in March 2006 to provide for dividend equivalent payments. We awarded 150,000 stock units vesting annually in equal amounts over eight years. Subject to forfeiture, our CEO will receive shares of common stock equal to the number of stock units vested when our CEO retires. At April 30, 2007, 94,000 units were vested. Amending the SERP in fiscal 2006 to provide for dividend equivalent payments increased the fair value of these units to $23.93 from $22.43 and increased the total cost of the units by $225.

All unvested shares of restricted stock and the SERP stock units would vest immediately upon the sale of the Company or the employees' death or disability. Unvested shares of restricted stock awarded before fiscal 2007 and the SERP stock units would also vest immediately upon a qualifying employment termination, but only a portion (based on the percentage of the vesting period elapsed) of the shares awarded to executive officers in February 2006 would vest immediately upon a qualifying employment termination. Unvested shares and units would be forfeited upon any other employment termination. Dividends are paid on all unvested shares of restricted stock. The restricted stock agreements and the SERP (as amended in March 2006) also allow employees to pay income taxes required to be withheld at vesting by surrendering a portion of the shares or units vested.

Stock options, shares of restricted stock and stock units are the only incentive compensation we provide (other than a cash bonus for the CEO) and we believe these stock-based awards further align employees' and directors' objectives with those of our stockholders. We issue new shares when options are exercised or when we award shares of restricted stock, and we do not have a policy to repurchase shares in the open market when options are exercised or when we award shares of restricted stock.

Stock option activity and related information for the nine months ended April 30, 2007 are summarized below (options and intrinsic value in thousands):

| | | Weighted-Average | | |
|---|---|---|---|---|
| | Options | Exercise Price | Remaining Term (years) | Intrinsic Value* |
| Outstanding - August 1, 2006 | 1,527 | $20.71 | | |
| Granted | 131 | 26.96 | | |
| Exercised | (313) | 16.77 | | |
| Forfeited | (67) | | | |
| Outstanding - April 30, 2007 | 1,278 | 22.22 | 2.6 | $5,600 |
| Exercisable - April 30, 2007 | 594 | $20.90 | 2.1 | $3,300 |

* number of options multiplied by the difference between the $26.28 closing price of our common stock on April 30, 2007 and the weighted-average exercise price



Information on stock option exercises follows (in thousands, except intrinsic value per option):

| Nine Months Ended April 30, | 2007 | 2006 |
|---|---|---|
| Number of options exercised | 313 | 324 |
| Total intrinsic value * | $3,400 | $3,900 |
| Intrinsic value per option | 10.86 | 12.03 |
| Excess tax benefits realized | 752 | 1,217 |

* options exercised multiplied by the difference between the closing prices of our common stock on the exercise dates and the exercise prices

Restricted stock activity under the 2006 Plan, the 1998 Plan and the MIP, and related information for the nine months ended April 30, 2007, are summarized below (shares in thousands):

| | Shares | Weighted-Average Grant-Date Fair Value |
|---|---|---|
| Unvested - August 1, 2006 | 1,081 | $24.66 |
| Granted | 120 | 26.96 |
| Vested | (142) | 21.38 |
| Forfeited | (9) | |
| Unvested - April 30, 2007 | 1,050 | 25.34 |

Information on shares of restricted stock that vested follows (in thousands, except intrinsic value per share):

| Nine Months Ended April 30, | 2007 | 2006 |
|---|---|---|
| Number of shares vested | 142 | 97 |
| Total intrinsic value * | $3,800 | $2,800 |
| Intrinsic value per share | 26.76 | 28.86 |
| Excess tax benefits realized | 350 | 365 |

* shares vested multiplied by the closing prices of our common stock on the dates vested

The weighted-average grant date fair value and exercise price of options granted, and the significant assumptions we used to calculate the fair values follow:

| Nine Months Ended April 30, | 2007 | 2006 |
|---|---|---|
| Weighted-average grant date fair value | $ 4.75 | $ 6.47 |
| Weighted-average exercise price | 26.96 | 28.80 |
| Weighted-average assumptions: | | |
| Expected life of options (in years) | 3.7 | 3.7 |
| Expected volatility | 22% | 25% |
| Risk-free interest rate | 4.5% | 4.6% |
| Dividend yield | 2.8% | 1.5% |

Future compensation expense (before deferral under SFAS No. 91) for stock-based awards unvested at April 30, 2007 and expected to vest, and the weighted-average expense recognition periods follow:

| | Expense | Weighted-Average Years |
|---|---|---|
| Restricted stock | $19,600 | 6.0 |
| Stock options | 1,700 | 2.6 |
| Stock units | 1,500 | 2.3 |
| Total | $22,800 | 5.5 |



Total compensation recorded, compensation capitalized (deferred recognizing) under SFAS No. 91, compensation included in salaries and other expenses and tax benefits recorded for stock-based awards follow:

| | Three Months Ended April 30, | | Nine Months Ended April 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Compensation for stock options: | | | | |
| Total recorded | $ 264 | $ 442 | $ 838 | $1,422 |
| Capitalized under SFAS No. 91 | 155 | 266 | 506 | 842 |
| Included in salaries and other expenses | $ 109 | $ 176 | $ 332 | $ 580 |
| Tax benefits recorded | $ 17 | $ 29 | $ 49 | $ 86 |
| Compensation for shares of restricted stock and stock units: | | | | |
| Total recorded | $1,485 | $1,198 | $4,193 | $2,863 |
| Capitalized under SFAS No. 91 | 540 | 484 | 1,633 | 1,208 |
| Included in salaries and other expenses | $ 945 | $ 714 | $2,560 | $1,655 |
| Tax benefits recorded | $ 357 | $ 276 | $ 973 | $ 636 |
| Total stock-based compensation: | | | | |
| Total recorded | $1,749 | $1,640 | $5,031 | $4,285 |
| Capitalized under SFAS No. 91 | 695 | 750 | 2,139 | 2,050 |
| Included in salaries and other expenses | $1,054 | $ 890 | $2,892 | $2,235 |
| Tax benefits recorded | $ 374 | $ 305 | $1,022 | $ 722 |

NOTE 7 - EARNINGS PER COMMON SHARE

Earnings per common share ("EPS") was calculated as follows (in thousands, except per share amounts):

| | Three Months Ended April 30, | | Nine Months Ended April 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Net income | $12,710 | $11,152 | $37,335 | $32,125 |
| Weighted-average common shares outstanding (used for basic EPS) | 26,042 | 26,017 | 26,177 | 25,844 |
| Effect of dilutive securities: | | | | |
| Stock options | 228 | 369 | 269 | 354 |

| | | | | |
|---|---|---|---|---|
| Shares of restricted stock and stock units | 259 | 204 | 284 | 219 |
| Adjusted weighted-average common shares outstanding (used for diluted EPS) | 26,529 | 26,590 | 26,730 | 26,417 |
| Earnings per common share: | | | | |
| Diluted | $ 0.48 | $ 0.42 | $ 1.40 | $ 1.22 |
| Basic | 0.49 | 0.43 | 1.43 | 1.24 |
| Antidilutive stock options, shares of restricted stock and stock units * | 310 | 300 | 200 | 325 |

* excluded from the calculation because they would have increased diluted EPS

The convertible debentures will lower diluted EPS when the quarterly average price of our common stock exceeds the adjusted conversion price. When this occurs, shares of common stock needed to deliver the value of the debentures over their principal amount based on the average stock price would be included as shares outstanding in calculating diluted EPS. Shares to be included would equal the difference between the average stock price and the adjusted conversion price, divided by the average stock price and multiplied by the number of convertible shares, currently 6,169,000 (referred to as the treasury stock method). The average price of our common stock was $27.10 and $27.52 for the three and nine months ended April 30, 2007, respectively, and the adjusted conversion price was $28.37 at April 30, 2007.



## Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

### OVERVIEW

Financial Federal Corporation is an independent financial services company operating in the United States through three wholly owned subsidiaries. We do not have any unconsolidated subsidiaries, partnerships or joint ventures. We also do not have any off-balance sheet assets or liabilities (other than commitments to extend credit), goodwill, other intangible assets or pension obligations, and we are not involved in income tax shelters. We have one fully consolidated special purpose entity we established for our on-balance-sheet asset securitization facility.

We have one line of business. We lend money under installment sale agreements, secured loans and leases (collectively referred to as "finance receivables") to small and medium sized businesses for their equipment financing needs. Finance receivable transactions generally range between $50,000 and $1.5 million, have terms generally ranging between two and five years and provide for monthly payments. The average transaction size is approximately $200,000. We earn revenue solely from interest and other fees and amounts earned on our finance receivables. We need to borrow most of the money we lend; therefore liquidity (money currently available for us to borrow) is important. We borrow from banks and insurance companies and we issue commercial paper to other investors. Approximately 75% of our finance receivables were funded with debt at April 30, 2007.

We focus on (i) maximizing the difference between the rates we earn on our receivables and the rates we incur on our debt ("net interest spread") (ii) maintaining the asset quality of our receivables and (iii) managing our interest rate risk. Interest rates on our finance receivables were 92% fixed and 8% floating, and interest rates on our debt were 48% fixed and 52% floating at April 30, 2007. Therefore, changes in market interest rates affect our profitability significantly. The asset quality of our finance receivables can also affect our profitability significantly. Asset quality can affect finance income, provisions for credit losses and operating expenses through reclassifying receivables to or from non-accrual status, incurring write-downs and incurring costs associated with non-performing assets. We use various strategies to manage our interest rate risk and credit risk.

Our main areas of focus are asset quality, liquidity and interest rate risk. We discuss each in detail in separate sections of this discussion. These areas are integral to our long-term profitability. Our key operating statistics are net charge-offs, loss ratio, non-performing assets, delinquencies, receivables growth, leverage, available liquidity, net interest margin and net interest spread, and expense and efficiency ratios.

### Significant events

In the third quarter of fiscal 2007, we increased the amount available under our stock repurchase program by $32.6 million and we repurchased 1.7 million shares of our common stock for $45.4 million paying a $26.80 weighted-average price per share. We completed the program in May 2007 with the repurchase of 159,000 shares for $4.3 million paying a $27.00 weighted-average price per share. The shares repurchased were 6.7% of total shares outstanding and increased our leverage to 4.3 from 3.9. This is discussed further in the Liquidity and Capital Resources section.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Accounting principles generally accepted in the United States require judgments, assumptions and estimates that affect the amounts reported in the Consolidated Financial Statements and accompanying notes. Note 1 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the fiscal year ended July 31, 2006 describes the significant accounting policies and methods used to prepare the Consolidated Financial Statements. Accounting policies involving significant judgment, assumptions and estimates are considered critical accounting policies and are described below.

### Allowance for Credit Losses

The allowance for credit losses on finance receivables is our estimate of losses inherent in our finance receivables at the balance sheet date. The allowance is difficult to determine and requires significant judgment. The allowance is based on total finance receivables, net charge-off experience, non-accrual and delinquent finance receivables and our current assessment of the risks inherent in our finance receivables from national and regional economic conditions, industry conditions, concentrations, the financial condition of customers and guarantors, collateral values and other factors. We may



need to change the allowance level significantly if unexpected changes in these conditions or factors occur. Increases in the allowance would reduce net income through higher provisions for credit losses. The allowance was $24.1 million (1.15% of finance receivables) at April 30, 2007 including $0.2 million specifically allocated to impaired receivables.

The allowance includes amounts specifically allocated to impaired receivables and an amount to provide for losses inherent in the remainder of finance receivables (the "general allowance"). We evaluate the fair value of an impaired receivable and compare it to the carrying amount. The carrying amount is the amount the receivable is recorded at when we evaluate the receivable and may include a prior write-down or specific allowance. If our estimate of fair value is lower than the carrying amount, we record a write-down or establish a specific allowance based on (i) how we determined fair value (ii) how certain we are of our estimate and (iii) the level and type of factors and items other than the primary collateral, such as guarantees and secondary collateral, supporting our fair value estimate.

To estimate the general allowance, we analyze historical write-down activity to develop percentage loss ranges by risk profile. Risk profiles are assigned to receivables based on past due status and the customers' industry. We then adjust the calculated range of losses for expected recoveries and we may also adjust the range for differences between current and historical loss trends and other factors to arrive at the estimated allowance. We record a provision for credit losses if the recorded allowance differs from our current estimate. Although our method is designed to calculate probable losses, because we use significant estimates, the adjusted calculated range of losses may differ from actual losses significantly.

Non-performing assets

We record impaired finance receivables at their current estimated fair value (if less than their carrying amount). We record assets received to satisfy receivables at their current estimated fair value less selling costs (if less than their carrying amount). We estimate fair value of non-performing assets by evaluating the expected cash flows of impaired receivables and the market value and condition of the collateral or assets. We evaluate market value based on recent sales of similar equipment, used equipment publications, our market knowledge and information from equipment vendors. Unexpected adverse changes in or incorrect estimates of expected cash flows, market value or the condition of collateral or assets, or time needed to sell the equipment would require us to record a write-down. This would lower net income. Impaired finance receivables and assets received to satisfy receivables (repossessed equipment) totaled $18.0 million (0.9% of finance receivables) at April 30, 2007.

Residual values

We record residual values on direct financing leases at the lowest of (i) any stated purchase option (ii) the present value at the end of the initial lease term of rentals due under any renewal options or (iii) our projection of the equipment's fair value at the end of the lease. We may not fully realize recorded residual values because of unexpected adverse changes in or incorrect projections of future equipment values. This would lower net income. Residual values totaled $42.4 million (2.0% of finance receivables) at April 30, 2007. Historically, we have realized the recorded residual value on disposition.

Stock-based compensation

We record compensation expense for stock options under SFAS No. 123R using the Black-Scholes option pricing model. This model requires us to estimate the expected volatility of the price of our common stock, the expected life of options and the expected dividend rate. SFAS No. 123R also requires us to estimate forfeitures of stock awards. Estimating volatility, expected life, dividend rate and forfeitures requires significant judgment and an analysis of historical data. If actual results differ from our estimates significantly, compensation expense for options and shares of restricted stock and our results of operations could be impacted materially.



RESULTS OF OPERATIONS

Comparison of three months ended April 30, 2007 to three months ended April 30, 2006

| ($ in millions, except per share amounts) | Three Months Ended April 30, 2007 | 2006 | $ Change | % Change |
|---|---|---|---|---|
| Finance income | $47.5 | $41.4 | $ 6.1 | 15% |
| Interest expense | 20.5 | 17.1 | 3.4 | 20 |
| Net finance income before provision for credit losses | 27.0 | 24.3 | 2.7 | 11 |
| Provision for credit losses | -- | -- | -- | -- |
| Salaries and other expenses | 6.3 | 6.0 | 0.3 | 5 |
| Provision for income taxes | 8.0 | 7.1 | 0.9 | 12 |
| Net income | 12.7 | 11.2 | 1.5 | 14 |
| Diluted earnings per share | 0.48 | 0.42 | 0.06 | 14 |
| Basic earnings per share | 0.49 | 0.43 | 0.06 | 14 |

Net income increased by 14% to $12.7 million in the third quarter of fiscal 2007 from $11.2 million in the third quarter of fiscal 2006. The increase resulted from receivables growth and the higher net yield on finance receivables, partially offset by the effects of higher short-term market interest rates.

Finance income increased by 15% to $47.5 million in the third quarter of fiscal 2007 from $41.4 million in the third quarter of fiscal 2006. The increase resulted from the 12% increase in average finance receivables ($215.0 million) to $2.08 billion in the third quarter of fiscal 2007 from $1.86 billion in the third quarter of fiscal 2006 and, to a lesser extent, the higher net yield on finance receivables. Higher market interest rates raised the net yield on finance receivables to 9.37% in the third quarter of fiscal 2007 from 9.12% in the third quarter of fiscal 2006.

Interest expense (incurred on debt used to fund finance receivables) increased by 20% to $20.5 million in the third quarter of fiscal 2007 from $17.1 million in the third quarter of fiscal 2006. The increase resulted from the 11% ($160.0 million) increase in average debt and higher short-term market interest rates. Increases in short-term market interest rates raised our weighted-average cost of debt to 5.33% in the third quarter of fiscal 2007 from 4.96% in the third quarter of fiscal 2006.

Net finance income before provision for credit losses on finance receivables increased by 11% to $27.0 million in the third quarter of fiscal 2007 from $24.3 million in the third quarter of fiscal 2006. Net interest margin (net finance income before provision for credit losses expressed as an annualized percentage of average finance receivables) decreased to 5.32% in the third quarter of fiscal 2007 from 5.34% in the third quarter of fiscal 2006.

We did not record provisions for credit losses on finance receivables in the third quarter of fiscal 2007 and 2006. The provision for credit losses is the amount needed to change the allowance for credit losses to our estimate of losses inherent in finance receivables. We did not need to increase the allowance because of continued low amounts of quarterly net charge-offs and continued strong asset quality, and we did not need to reduce it because of receivables growth. Net charge-offs (write-downs of finance receivables less recoveries) were $33,000 in the third quarter of fiscal 2007 and $89,000 in the third quarter of fiscal 2006, and the loss ratio (net charge-offs expressed as an annualized percentage of average finance receivables) was less than 0.01% in the third quarter of fiscal 2007 and was 0.02% in the third quarter of fiscal 2006.

Salaries and other expenses increased by 5% to $6.3 million in the third quarter of fiscal 2007 from $6.0 million in the third quarter of fiscal 2006. The increase resulted from fewer recoveries of costs associated with non-performing assets. The expense ratio (salaries and other expenses expressed as an annualized percentage of average finance receivables) improved to 1.23% in the third quarter of fiscal 2007 from 1.31% in the third quarter of fiscal 2006 because the percentage increase in receivables exceeded the percentage increase in expenses. The efficiency ratio (expense ratio expressed as a percentage of net interest margin) improved to 23.2% in the third quarter of fiscal 2007 from 24.6% in the third quarter of fiscal 2006 because the percentage increase in net finance income before provision for credit losses exceeded the percentage increase in expenses.



The provision for income taxes increased to $8.0 million in the third quarter of fiscal 2007 from $7.1 million in the third quarter of fiscal 2006. The increase resulted from the increase in income before income taxes, partially offset by the decrease in our effective tax rate to 38.6% in the third quarter of fiscal 2007 from 39.1% in the third quarter of fiscal 2006. Our effective tax rate decreased because of the new Texas income tax law enacted in our fourth quarter of fiscal 2006 and effective for fiscal 2007, and the overall decrease in our state effective income tax rate.

Diluted earnings per share increased by 14% to $0.48 per share in the third quarter of fiscal 2007 from $0.42 per share in the third quarter of fiscal 2006, and basic earnings per share increased by 14% to $0.49 per share in the third quarter of fiscal 2007 from $0.43 per share in the third quarter of fiscal 2006. The percentage increases in diluted and basic earnings per share were the same as the percentage increase in net income because the effects of our repurchase of 1.7 million shares of common stock offset the effects of stock option exercises.

Comparison of nine months ended April 30, 2007 to nine months ended April 30, 2006

| ($ in millions, except per share amounts) | Nine Months Ended April 30, 2007 | 2006 | $ Change | % Change |
|---|---|---|---|---|
| Finance income | $141.8 | $117.4 | $24.4 | 21% |
| Interest expense | 62.5 | 47.5 | 15.0 | 32 |
| Net finance income before provision for credit losses | 79.3 | 69.9 | 9.4 | 13 |
| Provision for credit losses | -- | -- | -- | -- |
| Salaries and other expenses | 18.5 | 17.2 | 1.3 | 7 |

| | | | | |
|---|---|---|---|---|
| Provision for income taxes | 23.5 | 20.6 | 2.9 | 14 |
| Net income | 37.3 | 32.1 | 5.2 | 16 |
| | | | | |
| Diluted earnings per share | 1.40 | 1.22 | 0.18 | 15 |
| Basic earnings per share | 1.43 | 1.24 | 0.19 | 15 |

Net income increased by 16% to $37.3 million in the first nine months of fiscal 2007 from $32.1 million in the first nine months of fiscal 2006. The increase resulted from receivables growth and the higher net yield on finance receivables, partially offset by the effects of higher short-term market interest rates and higher expenses.

Finance income increased by 21% to $141.8 million in the first nine months of fiscal 2007 from $117.4 million in the first nine months of fiscal 2006. The increase resulted from the 15% increase in average finance receivables ($267.0 million) to $2.05 billion in the first nine months of fiscal 2007 from $1.78 billion in the first nine months of fiscal 2006 and, to a lesser extent, the higher net yield on finance receivables. Higher market interest rates raised the net yield on finance receivables to 9.25% in the first nine months of fiscal 2007 from 8.80% in the first nine months of fiscal 2006.

Interest expense increased by 32% to $62.5 million in the first nine months of fiscal 2007 from $47.5 million in the first nine months of fiscal 2006. The increase resulted from higher average short-term market interest rates and the 15% ($209.0 million) increase in average debt. Increases in short-term market interest rates raised our weighted-average cost of debt to 5.36% in the first nine months of fiscal 2007 from 4.70% in the first nine months of fiscal 2006.

Net finance income before provision for credit losses on finance receivables increased by 13% to $79.3 million in the first nine months of fiscal 2007 from $69.9 million in the first nine months of fiscal 2006. Net interest margin decreased to 5.17% in the first nine months of fiscal 2007 from 5.25% in the first nine months of fiscal 2006 because the yield curve was inverted. This is discussed further in the Market Interest Rate Risk and Sensitivity section.

We did not record provisions for credit losses on finance receivables in the first nine months of fiscal 2007 and 2006. We did not need to increase the allowance because of continued low amounts of quarterly net charge-offs and continued strong asset quality, and we did not need to reduce it because of receivables growth. In the first nine months of fiscal 2007, there was a $15,000 net recovery (recoveries exceeded write-downs of finance receivables) compared to $198,000 of net charge-offs in the first nine months of fiscal 2006, and the loss ratio was near zero percent in the first nine months of fiscal 2007 and was 0.01% in the first nine months of 2006.



Salaries and other expenses increased by 7% to $18.5 million in the first nine months of fiscal 2007 from $17.2 million in the first nine months of fiscal 2006. The increase resulted from salary increases and fewer recoveries of costs associated with non-performing assets. The expense ratio improved to 1.21% in the first nine months of fiscal 2007 from 1.29% in the first nine months of fiscal 2006 because the percentage increase in receivables exceeded the percentage increase in expenses. The efficiency ratio improved to 23.3% in the first nine months of fiscal 2007 from 24.6% in the first nine months of fiscal 2006 because the percentage increase in net finance income before provision for credit losses exceeded the percentage increase in expenses.

The provision for income taxes increased to $23.5 million in the first nine months of fiscal 2007 from $20.6 million in the first nine months of fiscal 2006. The increase resulted from the increase in income before income taxes, partially offset by the decrease in our effective tax rate to 38.6% in the first nine months of fiscal 2007 from 39.1% in the first nine months of fiscal 2006. Our effective tax rate decreased because of the new Texas income tax law enacted in our fourth quarter of fiscal 2006 and effective for fiscal 2007, and the overall decrease in our state effective income tax rate.

Diluted earnings per share increased by 15% to $1.40 per share in the first nine months of fiscal 2007 from $1.22 per share in the first nine months of fiscal 2006, and basic earnings per share increased by 15% to $1.43 per share in the first nine months of fiscal 2007 from $1.24 per share in the first nine months of fiscal 2006. The percentage increases in diluted and basic earnings per share were lower than the percentage increase in net income because of stock option exercises.

FINANCE RECEIVABLES AND ASSET QUALITY

We discuss trends and characteristics of our finance receivables and our approach to managing credit risk in this section. The key aspect is asset quality. Asset quality statistics measure our underwriting standards, skills and policies and procedures and can indicate the direction and levels of future net charge-offs and non-performing assets.

| ($ in millions) | April 30, 2007 * | July 31, 2006 * | $ Change | % Change |
|---|---|---|---|---|
| Finance receivables | $2,097.9 | $1,991.7 | $106.2 | 5% |
| Allowance for credit losses | 24.1 | 24.1 | -- | -- |
| Non-performing assets | 18.0 | 14.6 | 3.4 | 24 |
| Delinquent finance receivables | 15.2 | 8.6 | 6.6 | 76 |
| Net charge-offs | -- | 0.1 | (0.1) | (100) |
| As a percentage of receivables: | | | | |
| Allowance for credit losses | 1.15% | 1.21% | | |
| Non-performing assets | 0.86 | 0.73 | | |
| Delinquent finance receivables | 0.72 | 0.43 | | |
| Net charge-offs | -- | 0.01 | | |

* as of and for the nine months ended

Finance receivables grew 5% ($106 million) during the first nine months of fiscal 2007 to $2.10 billion at April 30, 2007 from $1.99 billion at July 31, 2006. Finance receivables comprise installment sale agreements and secured loans (collectively referred to as loans) and direct financing leases. Loans were 90% ($1.89 billion) of finance receivables and leases were 10% ($204 million) at April 30, 2007.

Finance receivables originated in the third quarter of fiscal 2007 and 2006 were $307 million and $360 million, respectively, and finance receivables originated in the first nine months of fiscal 2007 and 2006 were $911 million and $1.01 billion, respectively. Originations decreased because the strong demand for equipment financing eased due to general economic conditions. Finance receivables collected in the third quarter of fiscal 2007 and 2006 were $257 million and $248 million, respectively, and finance receivables collected in the first nine months of fiscal 2007 and 2006 were $795 million and $744 million, respectively. Collections increased because of higher average receivables.

Our primary focus is the credit quality of our receivables. We manage our credit risk by using disciplined and sound underwriting policies and procedures, by monitoring our receivables closely and by handling non-performing accounts effectively. Our underwriting policies and procedures require a first lien on equipment financed. We focus on financing equipment with a remaining useful life longer than the term financed, historically low levels of technological obsolescence,



use in more than one type of business, ease of access and transporting, and broad, established resale markets. Securing our receivables with equipment possessing these characteristics can mitigate potential net charge-offs. We may also obtain additional equipment or other collateral, third-party guarantees, advance payments or hold back a portion of the amount financed. We do not finance or lease aircraft or railcars, computer related equipment, telecommunications equipment or equipment located outside the United States, and we do not lend to consumers.

Our underwriting policies limit our credit exposure with any customer. This limit was $40.0 million at April 30, 2007. Our ten largest customers accounted for 5.8% ($122.0 million) of total finance receivables at April 30, 2007.

Our allowance for credit losses was $24.1 million at April 30, 2007 and July 31, 2006. The allowance level declined to 1.15% of finance receivables at April 30, 2007 from 1.21% at July 31, 2006 because of continued low net charge-offs, favorable asset quality and receivables growth. We determine the allowance quarterly based on our analysis of historical losses and the past due status of receivables at the end of each quarter adjusted for expected recoveries and any differences between current and historical loss trends and other factors.

In the first nine months of fiscal 2007, there was a $15,000 net recovery (recoveries exceeded write-downs of finance receivables) compared to $88,000 of net charge-offs (write-downs less recoveries) in the last nine months of fiscal 2006 (the prior nine month period). Net charge-offs were $33,000 in the third quarter of fiscal 2007 compared to a $101,000 net recovery in the second quarter of fiscal 2007. Net charge-offs remained low because of low non-performing assets.

The net investments in non-accrual (impaired) finance receivables, repossessed equipment (assets received to satisfy receivables), total non-performing assets and delinquent finance receivables (transactions with more than a nominal portion of a contractual payment 60 or more days past due) follow ($ in millions):

| | April 30, 2007 | July 31, 2006 | April 30, 2006 |
|---|---|---|---|
| Non-accrual finance receivables * | $ 15.9 | $ 13.8 | $ 12.1 |
| Repossessed equipment | 2.1 | 0.8 | 0.4 |
| Total non-performing assets | $ 18.0 | $ 14.6 | $ 12.5 |

| | | | |
|---|---|---|---|
| Delinquent finance receivables | $ 15.2 | $ 8.6 | $ 4.9 |
| Percentage of non-accrual receivables not delinquent | 46% | 54% | 75% |

* before specifically allocated allowance of $0.2 million at April 30, 2007, $0.3 million at July 31, 2006 and $0.5 million at April 30, 2006

Delinquent receivables, non-accrual receivables and repossessed equipment increased during the third quarter and first nine months of fiscal 2007 but are still at favorable levels and the increases do not necessarily indicate the start of a negative trend. Also, because our asset quality statistics remained below expected levels, they could worsen significantly if receivables from our larger customers become delinquent, impaired or repossessed even though the overall trend may remain positive.

## LIQUIDITY AND CAPITAL RESOURCES

We describe our need for raising capital (debt and equity), our need for a substantial amount of liquidity (money currently available for us to borrow), our approach to managing liquidity and our current funding sources in this section. Key indicators are leverage (the number of times debt exceeds equity), available liquidity, credit ratings and debt diversification. Our leverage is low for a finance company, we have been successful in issuing debt, we have ample liquidity available and our debt is diversified with maturities staggered over seven years.

Liquidity and access to capital are vital to our operations and growth. We need continued availability of funds to originate or acquire finance receivables and to repay debt. To ensure we have enough liquidity, we project our financing needs based on estimated receivables growth and maturing debt, we monitor capital markets closely and we diversify our funding sources. Funding sources available to us include operating cash flow, private and public issuances of term debt, conduit and term securitizations of finance receivables, committed unsecured revolving bank credit facilities, dealer placed

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and direct issued commercial paper and sales of common and preferred equity. We believe our liquidity sources are diversified, and we are not dependent on any funding source or provider.

Our term notes are rated 'BBB+' by Fitch Ratings, Inc. ("Fitch", a Nationally Recognized Statistical Ratings Organization) and our commercial paper is rated 'F2' by Fitch. As a condition of our 'F2' credit rating, commercial paper outstanding is limited to the unused amount of our bank credit facilities. Fitch affirmed its investment grade ratings on our debt in January 2007 maintaining its stable outlook. Our access to capital markets and our credit spreads are partly dependent on these investment grade credit ratings.

We had $248.9 million available to borrow at April 30, 2007; $206.4 million under our bank credit facilities (after subtracting commercial paper outstanding) and $42.5 million under our asset securitization facility. Our asset securitization facility could also be increased by $335.0 million and we believe we can issue more term notes. We believe, but cannot assure, sufficient capital is available to us to sustain our future operations and growth.

Our major operating subsidiary's debt agreements have restrictive covenants including limits on its indebtedness, encumbrances, investments, dividends and other distributions to us, sales of assets, mergers and other business combinations, capital expenditures, interest coverage and net worth. We were in compliance with all debt covenants at April 30, 2007. None of the agreements have a material adverse change clause.

Debt increased by 7% ($105.0 million) to $1.63 billion at April 30, 2007 from $1.53 billion at July 31, 2006 and stockholders' equity decreased by 2% ($7.5 million) to $382.9 million at April 30, 2007 from $390.4 million at July 31, 2006 because we repurchased $45.9 million of common stock. Therefore, leverage increased to 4.3 at April 30, 2007 from 3.9 at July 31, 2006. Our leverage is still considered low allowing for substantial asset growth and additional equity repurchases. Historically, our leverage has not exceeded 5.5 which is also considered low for a finance company.

Debt comprised the following ($ in millions):

| | April 30, 2007 | | July 31, 2006 | |
|---|---|---|---|---|
| | Amount | Percent | Amount | Percent |
| Term notes | $ 754.5 | 46% | $ 664.5 | 43% |
| Asset securitization financings | 382.5 | 23 | 425.0 | 28 |
| Commercial paper | 289.9 | 18 | 118.9 | 8 |
| Convertible debentures | 175.0 | 11 | 175.0 | 11 |
| Borrowings under bank credit facilities | 33.7 | 2 | 149.7 | 10 |
| Total principal | 1,635.6 | 100% | 1,533.1 | 100% |
| Fair value adjustment of hedged debt | (2.9) | | (5.4) | |
| Total debt | $1,632.7 | | $1,527.7 | |

Term Notes

We issued $125.0 million of fixed rate term notes in April 2007. The notes comprise $75.0 million of five-year, 5.48% notes and $50.0 million of seven-year, 5.57% notes due at maturity in April 2012 and 2014. We will pay interest semiannually. We repaid bank and securitization borrowings with the proceeds.

We repaid $25.0 million of 5.92% fixed rate term notes at maturity and we converted a $10.0 million floating rate term note from a bank due in fiscal 2008 to a $15.0 million three-year committed unsecured revolving credit facility in the first nine months of fiscal 2007.

Asset Securitization Financings

We have a $425.0 million asset securitization facility. We established the facility in July 2001. The facility was renewed a sixth time in April 2007 and expires in April 2008 subject to further renewal. The facility limits borrowings to a minimum level of securitized receivables. If borrowings exceed the minimum level, we must repay the excess or securitize more receivables. We can securitize more receivables during the term of the facility. On expiration and nonrenewal of the facility, we must repay borrowings outstanding or convert them into term debt. The term debt would be repaid monthly and would be fully repaid by December 2009 based on the contractual payments of the $478.0 million of securitized receivables at April 30, 2007.

The unsecured debt agreements of our major operating subsidiary allow 40% of its finance receivables to be securitized ($835.0 million at April 30, 2007). Therefore, we could securitize an additional $357.0 million of finance receivables at April 30, 2007. Borrowings are limited to 94% of securitized receivables and can be further limited based on the eligibility of securitized receivables.

Convertible Debentures

We irrevocably elected in fiscal 2005 to pay the value of converted debentures, not exceeding the principal amount, in cash instead of issuing shares of our common stock. We still would need to pay any value over principal with common stock. The value of the convertible debentures equals the number of convertible shares multiplied by the market value of our common stock. There are 6.2 million convertible shares (as adjusted), the adjusted conversion price is $28.37 per share and the adjusted conversion rate is 35.25 shares for each $1,000 of principal. No event allowing for the debentures to be converted has occurred through April 30, 2007.

Bank Credit Facilities

We have $530.0 million of committed unsecured revolving credit facilities from ten banks (a $60.0 million increase from July 31, 2006). This includes $450.0 million of facilities with original terms ranging from two to five years and $80.0 million of facilities with an original term of one year. In the first nine months of fiscal 2007, $142.5 million of one year facilities were converted into multi-year facilities. Borrowings under these facilities can mature between 1 and 270 days. We can borrow the full amount under each facility. These facilities may be renewed or extended before they expire.

Commercial Paper

We issue commercial paper direct and through a $500.0 million program with maturities between 1 and 270 days. We increased the size of our commercial paper program in the second quarter of fiscal 2007 from $350.0 million. The combined amount of commercial paper and bank borrowings ($323.6 million April 30, 2007) was limited to $530.0 million because commercial paper outstanding is limited to the unused amount of our bank credit facilities. Commercial paper outstanding increased during the first nine months of fiscal 2007 because we added a commercial paper dealer.

Stockholders' Equity

We increased the amount available under our common stock and convertible debt repurchase program by $32.6 million and we repurchased 1.7 million shares of our common stock for $45.4 million paying a weighted-average price of $26.80 per share in the third quarter of fiscal 2007. We financed the repurchases with the proceeds from the seven-year fixed rate term notes issued in April 2007 and with borrowings under our bank credit facilities. We also received 17,500 shares of common stock from employees in the first nine months of fiscal 2007 at a weighted-average price of $26.70 per share for payment of income tax we were required to withhold on vested shares of restricted stock. We retired all shares repurchased and received in fiscal 2007.

We paid $10.9 million of cash dividends and we received $6.4 million from stock option exercises and tax benefits from stock-based awards in the first nine months of fiscal 2007.

MARKET INTEREST RATE RISK AND SENSITIVITY

We discuss how changes in market interest rates affect our net interest spread and how we manage interest rate risk in this section. Net interest spread (the net yield of finance receivables less the weighted-average cost of debt) is an integral part of a finance company's profitability and is calculated below:

| | Three Months Ended April 30, | | Nine Months Ended April 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Net yield of finance receivables | 9.37% | 9.12% | 9.25% | 8.80% |
| Weighted-average cost of debt | 5.33 | 4.96 | 5.36 | 4.70 |
| Net interest spread | 4.04% | 4.16% | 3.89% | 4.10% |

Our net interest spread was 0.12% (12 basis points) lower in the third quarter of fiscal 2007 compared to the third quarter of fiscal 2006, and was 0.21% (21 basis points) lower in the first nine months of fiscal 2007 compared to the first nine months of fiscal 2006 because the effects of higher average short-term market interest rates on our cost of debt exceeded the increase in the net yield of finance receivables. This is an expected result of an inverted yield curve as discussed below.



Our net interest spread is sensitive to changes in short-term and long-term market interest rates (includes LIBOR, rates on U.S. Treasury securities, money-market rates, swap rates and the prime rate). Increases in short-term rates reduce our net interest spread (this occurred during our prior two fiscal years) and decreases in short-term rates increase our net interest spread because our floating rate debt (includes short-term debt) exceeds our floating rate finance receivables by a significant amount. Interest rates on our debt change faster than the yield on our receivables because 52% of our debt is floating rate compared to floating rate finance receivables of only 8%. Our net interest spread is also affected when the differences between short-term and long-term rates change. Long-term rates normally exceed short-term rates. When this excess narrows (resulting in a "flattening yield curve") or when short-term rates exceed long-term rates (an "inverted yield curve"), our net interest spread should decrease and when the yield curve widens our net interest spread should increase because the rates we charge our customers are partially determined by long-term market interest rates and rates on our floating rate debt are largely determined by short-term market interest rates. We can mitigate the effects of an inverted yield curve by issuing long-term fixed rate debt.

Short-term market interest rates changed little during the first nine months of fiscal 2007 after rising substantially and consistently over the prior two years. As a result, our weighted-average cost of debt decreased by 0.03% (3 basis points) in the third quarter of fiscal 2007 compared to quarterly increases of 0.25% (25 basis points) during the prior two fiscal years. The increase in our weighted-average cost of debt during the first nine months of fiscal 2007 was only 0.07% (7 basis points).

Our income is subject to the risk of rising short-term market interest rates and an inverted yield curve at April 30, 2007 because floating rate debt exceeded floating rate receivables by $681.7 million (see the table below). The terms and prepayment experience of our fixed rate receivables mitigate this risk. Finance receivables are collected monthly over short terms of two to five years and have been accelerated by prepayments. At April 30, 2007, $695.0 million (36%) of fixed rate finance receivables are scheduled to be collected in one year and the weighted-average remaining life of fixed rate finance receivables excluding prepayments is approximately twenty months. We do not match the maturities of our debt to our finance receivables. The fixed and floating rate amounts and percentages of our finance receivables and capital at April 30, 2007 follow ($ in millions):

| | Fixed Rate | | Floating Rate | | |
|---|---|---|---|---|---|
| | Amount | Percent | Amount | Percent | Total |
| Finance receivables | $1,930.3 | 92% | $167.6 | 8% | $2,097.9 |
| Debt (principal) | $ 786.3 | 48% | $849.3 | 52% | $1,635.6 |
| Stockholders' equity | 382.9 | 100 | -- | -- | 382.9 |
| Total debt and equity | $1,169.2 | 58% | $849.3 | 42% | $2,018.5 |

Floating rate debt comprises asset securitization financings, commercial paper, floating rate swaps of fixed rate notes and bank borrowings, and reprices (interest rate changes based on current short-term market interest rates) at April 30, 2007 as follows: $646.2 million (76%) within one month, $86.9 million (10%) in two to three months and $116.2 million (14%) in four to six months. Most of the floating rate swaps of fixed rate notes last repriced in April 2007. The repricing frequency of floating rate debt follows (in millions):

| | Balance | Repricing Frequency |
|---|---|---|
| Asset securitization financings | $382.5 | generally daily |
| Commercial paper | 289.9 | 1 to 90 days (20 day average) |
| Floating rate swaps of fixed rate notes | 143.3 | semiannually (150 day average) |
| Bank borrowings | 33.7 | generally daily |

We quantify interest rate risk by calculating the effect on net income of a hypothetical, immediate 100 basis point (1.0%) rise in market interest rates. This hypothetical change in rates would reduce quarterly net income by approximately $0.6 million at April 30, 2007 based on scheduled repricings of floating rate debt, fixed rate debt maturing within one year and the expected effects on the yield of new receivables. This amount increases to $1.0 million excluding the expected increase in the yield of new receivables. We believe these amounts are acceptable considering the cost of floating rate debt has been historically lower than fixed rate debt. Actual future changes in market interest rates and the effect on net income may differ materially from these amounts. Other factors that may accompany an actual immediate 100 basis point rise in market interest rates were not considered in the calculation.

We monitor and manage our exposure to potential adverse changes in market interest rates with derivative financial instruments and by changing the proportion of our fixed and floating rate debt. We may use derivatives to hedge our exposure to interest rate risk on existing debt and debt expected to be issued. We do not speculate with or trade derivatives.

We entered into interest rate locks with a total notional amount of $100.0 million with three banks in September 2006. The rate locks had a March 2007 expiration. We designated the rate locks as cash flow hedges of our anticipated issuance of fixed rate term notes hedging the risk of higher interest payments on the notes for the first five years from increases in market interest rates before the notes were issued. We terminated the rate locks in January 2007 at a $1.0 million gain. We would have realized a small loss if we let the rate locks expire.

We entered into another interest rate lock with a notional amount of $50.0 million with a bank in March 2007 with an April 2007 expiration. We designated it as a cash flow hedge of the same anticipated fixed rate term notes issuance originally hedged in September 2006. We hedged these notes again because applicable market interest rates declined more than 0.40% (40 basis points) after we terminated the first three rate locks. We terminated this rate lock in April 2007 when the hedged notes were issued and we realized a $169,000 gain. The four rate locks were determined to be highly effective.

The amount of the gains on these four rate locks relating to hedge ineffectiveness was $100,000. We recorded this amount as a reduction of interest expense in the three and nine months ended April 30, 2007. We recorded the $1.1 million effective amount of these gains in stockholders' equity as accumulated other comprehensive income net of deferred income tax of $0.4 million. We are reclassifying this after-tax amount into net income over five years by reducing interest expense and deferred income tax. These rate locks effectively lowered the interest rate on the fixed rate notes issued in April 2007 by 0.20% (20 basis points).

We also have fixed to floating interest rate swaps with a total notional amount of $143.3 million at April 30, 2007 and July 31, 2006. The swaps effectively converted fixed rate term notes into floating rate term notes. Semiannually, we receive fixed amounts from the swap counterparty banks equal to the interest we pay on the hedged fixed rate notes, and we pay amounts to the swap counterparty banks equal to the swaps' floating rates multiplied by the swaps' notional amounts. The swaps' floating rates change semiannually to a fixed amount over six-month LIBOR (5.36% at April 30, 2007). The swaps increased interest expense by $0.8 million in the third quarter of fiscal 2007 and by $2.3 million in the first nine months of fiscal 2007. The weighted-average pay rate of 6.89% at April 30, 2007 exceeded the 4.88% weighted-average receive rate by 201 basis points (2.01%). The weighted-average remaining term of the swaps at April 30, 2007 is 1.3 years.

NEW ACCOUNTING STANDARDS

The Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - An Interpretation of FASB 109", ("FIN No. 48") in July 2006. FIN No. 48 requires companies to determine if any tax positions taken on their income tax returns lowering the amount of tax currently due would more likely than not be allowed by a taxing jurisdiction. If tax positions pass the more-likely-than-not test, companies then record benefits from them only equal to the highest amount having a greater than 50% chance of being realized assuming the tax positions would be challenged by a taxing jurisdiction. No benefits would be recorded for tax positions failing the more-likely-than-not test. Tax benefits include income tax savings and the related interest expense savings. Whether tax positions pass the test or not, adopting FIN No. 48 could result in additional income tax provisions or expenses for any interest and penalties on potential underpayments of income tax, or both. FIN No. 48 is effective in the first quarter of fiscal years beginning after December 15, 2006. It will become effective for us on August 1, 2007, the beginning of our fiscal year ending July 31, 2008. We are evaluating how it may affect our consolidated financial statements.

The FASB issued Statement of Financial Accounting Standards ("SFAS") No. 157, "Fair Value Measurements", ("SFAS No. 157") in September 2006. SFAS No. 157 defines fair value (replacing all prior definitions) and creates a framework to measure fair value, but does not create any new fair value measurements. SFAS No. 157 is effective in the first quarter of fiscal years beginning after November 15, 2007. It will become effective for us on August 1, 2008. We are evaluating how it may affect our consolidated financial statements.

The FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - Including an amendment of FASB Statement No. 115" in February 2007. SFAS No. 159 permits companies to choose to measure many financial instruments and certain other items at fair value at specified election dates and to report unrealized gains and losses on these items in earnings at each subsequent reporting date. SFAS No. 159 is effective in the first quarter of fiscal



years beginning after November 15, 2007. It will become effective for us on August 1, 2008. We are evaluating how it may affect our consolidated financial statements.

FORWARD-LOOKING STATEMENTS

Statements in this report including the words or phrases "can be," "expect," "anticipate," "may," "believe," "estimate," "intend," "could," "should," "would," "if" and similar words and phrases are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are subject to various known and unknown risks and uncertainties and any forward-looking information provided by us or on our behalf is not a guarantee of future performance. Our actual results could differ from those anticipated by forward-looking statements materially because of the uncertainties and risks described in "Part I, Item 1A Risk Factors" in our Annual Report on Form 10-K for the year ended July 31, 2006 and other sections of this report. These risk factors include (i) an economic slowdown (ii) the inability to collect finance receivables and the sufficiency of the allowance for credit losses (iii) the inability to obtain capital or maintain liquidity (iv) rising short-term market interest rates and adverse changes in the yield curve (v) increased competition (vi) the inability to retain key employees and (vii) adverse conditions in the construction and road transportation industries. Forward-looking statements apply only as of the date made and we are not required to update forward-looking statements for future or unanticipated events or circumstances.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

See the Market Interest Rate Risk and Sensitivity Section in Part I Item 2.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures.

Our management (with our Chief Executive Officer's and Chief Financial Officer's participation) evaluated our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) at the end of the period covered by this report. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded our disclosure controls and procedures are effective to ensure information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported timely.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the third quarter of fiscal 2007 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

ISSUER PURCHASES OF EQUITY SECURITIES
For the Quarter Ended April 30, 2007

| Month | (a) Total Number of Shares Purchased | (b) Average Price Paid per Share | (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | (d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| March 2007 | 643,059 | $ 26.43 | 643,059 | $ 33,025,000 |
| April 2007 | 1,062,635 | $ 27.03 | 1,062,635 | $ 4,300,000 |

We did not sell any unregistered shares of common stock during the third quarter of fiscal 2007. We increased the amount available under our common stock and convertible debt repurchase program by $32.6 million in the third quarter of fiscal 2007. Shares repurchased during the quarter include 1.7 million shares purchased on the open market and 12,500



shares received from employees for payment of income tax we were required to withhold on vested shares of restricted stock. We retired all shares repurchased and received in the third quarter of fiscal 2007. A total of $73.3 million was authorized for repurchases of common stock and convertible debt since the program's inception and we repurchased 2.8 million shares of common stock for $61.8 million and $8.8 million of convertible debt for $7.2 million through April 30, 2007. We completed the program in May 2007 with the repurchase of

159,000 shares for $4.3 million paying a $27.00 weighted-average price per share.

Item 5. Other Information

We issued a press release on June 4, 2007 reporting our results for the quarter ended April 30, 2007. The press release is attached as Exhibit 99.1. Exhibit 99.1 shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or subject to the liabilities of that section, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference.

We issued a press release on June 4, 2007 announcing our Board of Directors declared a quarterly dividend of $0.15 per share on our common stock and authorized a new $50 million common stock and convertible debt repurchase program. The press release is attached as Exhibit 99.2. The dividend is payable on July 10, 2007 to stockholders of record at the close of business on June 22, 2007. The dividend rate is the same as the previous quarter.

Item 6. Exhibits

| Exhibit No. | | Description of Exhibit |
|---|---|---|
| 3.1 | (a) | Articles of Incorporation |
| 3.2 | (b) | Certificate of Amendment of Articles of Incorporation dated December 9, 1998 |
| 3.3 | (c) | Amended and Restated By-laws dated March 5, 2007 |
| 31.1 | | Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer |
| 31.2 | | Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer |
| 32.1 | | Section 1350 Certification of Chief Executive Officer |
| 32.2 | | Section 1350 Certification of Chief Financial Officer |
| 99.1 | | Press release dated June 4, 2007 |
| 99.2 | | Press release dated June 4, 2007 |

Previously filed with the Securities and Exchange Commission as an exhibit to our:

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(a) Registration Statement on Form S-1 (Registration No. 33-46662) filed May 28, 1992
(b) Form 10-Q for the quarter ended January 31, 1999
(c) Form 10-Q for the quarter ended January 31, 2007



SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

FINANCIAL FEDERAL CORPORATION
(Registrant)

By: /s/ Steven F. Groth
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Senior Vice President and
Chief Financial Officer
(Principal Financial Officer)

By: /s/ David H. Hamm
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Vice President and Controller
(Principal Accounting Officer)

June 5, 2007
------------
(Date)



style="font-family:times;">

| | | | | | |
|---|---|---|---|---|---|
| Energy sales | $152.0 | $84.9 | $79.0 | $ | $315.9 |
| Energy capacity revenue | 116.0 | 45.3 | | | 161.3 |
| Other | 45.8 | 45.0 | 0.3 | 0.9 | 92.0 |
| | 313.8 | 175.2 | 79.3 | 0.9 | 569.2 |
| Project expenses: | | | | | |
| Fuel | 148.0 | 62.3 | | 0.1 | 210.4 |
| Operations and maintenance | 55.6 | 48.8 | 21.1 | 4.7 | 130.2 |
| Development | | | | 3.7 | 3.7 |
| Depreciation and amortization | 68.3 | 53.3 | 40.3 | 0.7 | 162.6 |
| | 271.9 | 164.4 | 61.4 | 9.2 | 506.9 |

Project other income (expense):

Change in fair value of derivative instruments

8.0 (15.5) (1.2) (8.7)

Equity in earnings of unconsolidated affiliates

22.3 3.3 0.3 (0.1) 25.8

Gain on sale of equity investments

8.6 8.6

Interest expense, net

(17.7) (14.2) (31.9)

Impairment

(32.7) (74.0) 0.1 (106.6)

Other expense, net

(20.1) (62.1) (29.4) (1.2) (112.8)

Project income (loss)

$21.8 $(51.3) $(11.5) $(9.5) $(50.5)

| | Year Ended December 31, 2013 | | | | |
|---|---|---|---|---|---|
| | East[1] | West[2] | Wind | Un-allocated Corporate[3] | Consolidated Total |
| Project revenue: | | | | | |
| Energy sales | $ 150.1 | $ 81.6 | $ 70.6 | $ (0.1) | $ 302.2 |
| Energy capacity revenue | 118.3 | 45.6 | | (0.2) | 163.7 |
| Other | 30.7 | 47.5 | 0.2 | (0.2) | 78.2 |
| | 299.1 | 174.7 | 70.8 | (0.5) | 544.1 |
| Project expenses: | | | | | |
| Fuel | 135.0 | 59.2 | | 0.1 | 194.3 |
| Operations and maintenance | 63.7 | 55.5 | 20.8 | 10.8 | 150.8 |
| Development | | | | 7.2 | 7.2 |
| Depreciation and amortization | 68.9 | 54.9 | 41.8 | 0.5 | 166.1 |
| | 267.6 | 169.6 | 62.6 | 18.6 | 518.4 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | 25.5 | | 24.0 | | 49.5 |
| Equity in earnings of unconsolidated affiliates | 21.3 | 4.5 | 1.1 | | 26.9 |
| Gain on sale of equity investments | | 30.4 | | | 30.4 |
| Interest expense, net | (19.6) | (0.1) | (14.6) | (0.1) | (34.4) |

| | | | | | |
|---|---|---|---|---|---|
| Impairment | (30.8) | (4.1) | | | (34.9) |
| Other expense, net | (2.1) | | (0.1) | 2.7 | 0.5 |
| | (5.7) | 30.7 | 10.4 | 2.6 | 38.0 |
| Project income (loss) | $ 25.8 | $ 35.8 | $ 18.6 | $ (16.5) | $ 63.7 |

(1) Excludes the Florida Projects which are classified as discontinued operations.

(2) Excludes Path 15 and Greeley which are classified as discontinued operations.

(3) Excludes Rollcast which is designated as discontinued operations.

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***East***

Project income for 2014 decreased $4.0 million or 15.5% from 2013 primarily due to:

- increased project loss of $12.0 million at Tunis due primarily to a $14.8 million non-cash goodwill and long-lived asset impairment charge recorded during the year ended December 31, 2014;

- decreased project income of $11.9 million at Selkirk due primarily to lower energy revenue resulting from lower generation from mild weather conditions, as well as accelerated depreciation resulting from the expiration of the project's PPA in August 2014. Selkirk is operating as a 100% merchant facility subsequent to the expiration of the project's PPA;

- decreased project income of $9.2 million at Piedmont due primarily to a negative $9.7 million non-cash change in the fair value of interest rate swap agreements that are accounted for as derivatives;

- decreased project income at North Bay of $2.8 million due primarily to a negative $5.5 million non-cash change in the fair value of gas purchase agreements that are accounted for as derivatives, partially offset by increased energy revenue from higher waste heat generation than in the comparable 2013 period; and

- decreased project income of Kapuskasing of $2.5 million due primarily to a negative $5.5 million non-cash change in the fair value of gas purchase agreements that are accounted for as derivatives and $2.6 million in decreased revenues, partially offset by a $3.6 million decrease in fuel expense and a $1.3 million decrease in operations and maintenance expense.

These decreases were partially offset by:

- increased project income of $11.4 million at Kenilworth due primarily to a $17.9 million goodwill impairment charge recorded during the year ended December 31, 2014 as compared to a $30.7 million goodwill impairment charge recorded during the comparable 2013 period;

- increased project income of $9.5 million at Orlando due primarily to a $4.9 million increase in revenue resulting from increased generation and a $5.5 million decrease in fuel costs compared to the 2013 period. Orlando operated under an above-market fuel supply agreement that expired in the fourth quarter of 2013;

- increased project income of $6.6 million at Morris due primarily to a $14.4 million increase in energy revenues. Energy payments were escalated under the terms of the project's PPA due to higher natural gas prices. This increase was offset by higher fuel expenses compared to the 2013 period;

- increased project income of $6.4 million at Nipigon due primarily to a positive $4.0 million non-cash change in the fair value of a gas purchase agreement that is accounted for as a derivative, as well as a $2.4 million decrease in maintenance expenses as compared to the 2013 period, during which the project underwent a scheduled turbine outage. Nipigon also underwent a five-week outage during the third quarter of 2014 to upgrade its steam generator. Costs related to this project are being capitalized; and

- increased project income of $4.4 million at Curtis Palmer due primarily to a $5.0 million decrease in interest expense related to the project's repayment of its senior unsecured notes with proceeds from our Senior Secured Credit Facilities.

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***West***

Project income for 2014 decreased $87.1 million from 2013 primarily due to:

- decreased project income of $52.3 million at Manchief due primarily to a $50.2 million goodwill impairment charge recorded during the year ended December 31, 2014;
- decreased project income of $32.0 million at Gregory due to the sale of the project in August 2013, which resulted in a gain on sale of approximately $31.0 million recorded during the comparable 2013 period; and
- decreased project income of $23.0 million at Williams Lake due primarily to a $23.7 million goodwill impairment charge recorded during the year ended December 31, 2014.

These decreases were partially offset by:

- increased project income of $8.1 million at Delta-Person which was sold in July 2014, which resulted in a gain on sale of $8.6 million recorded during 2014;
- increased project income of $3.9 million at Naval Station due primarily to $2.8 million of increased revenue due primarily to higher generation and energy prices resulting from higher gas prices during the 2014 period;
- increased project income of $3.6 million at Naval Training due primarily to decreased maintenance expenses as compared to the comparable 2013 period, during which the project underwent a scheduled turbine overhaul; and
- increased project income of $3.6 million at Mamquam due primarily to decreased maintenance expenses as compared to the comparable 2013 period, during which the project underwent a scheduled turbine overhaul.

Project income for the West segment excludes the Path 15 and Greeley projects which are accounted for as a component of discontinued operations. Project income for Path 15 was $0.0 million and $2.1 million for the years ended December 31, 2014 and 2013, respectively. The decrease in 2014 compared to 2013 is due primarily to the project being sold in April 2013. Project (loss) income for Greeley was ($0.1) million and $0.6 million for the years ended December 31, 2014 and 2013, respectively. The decrease in 2014 compared to 2013 is due primarily to the project being sold in March 2014.

***Wind***

Project income for 2014 decreased $30.1 million from 2013 primarily due to:

- decreased project income from Rockland of $15.0 million due primarily to a negative $17.0 million non-cash change in the fair value of interest rate swap agreements that are accounted for as derivatives; and
- decreased project income from Meadow Creek of $15.0 million due primarily to a negative $22.5 million non-cash change in the fair value of interest rate swap agreements that are accounted for as derivatives, partially offset by $5.5 million of increased revenue due to higher generation compared to the 2013 period.

***Un-allocated Corporate***

Total project loss decreased $7.0 million from 2013 primarily due to a $3.5 million decrease in development and administrative costs at Ridgeline, which was acquired in December 2012, as well as administrative reduction initiatives undertaken during the year ended December 31, 2014.

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***Administrative and other expenses (income)***

Administrative and other expenses (income) include the income and expenses not attributable to our projects and are allocated to the Un-allocated Corporate segment. These costs include the activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate tax. Significant non-cash items that impact Administrative and other expenses (income), which are subject to potentially significant fluctuations, include the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar-denominated obligations and the related deferred income tax expense (benefit) associated with these non-cash items.

*Administration*

Administration expense increased $2.7 million or 8% from 2013 primarily due to a $3.9 million increase in labor costs primarily due to $6.0 million of employee severance expenses incurred during the third and fourth quarters of 2014 which are expected to result in lower administrative costs on a go-forward basis.

*Interest, net*

Interest expense increased $42.6 million or 41% from the comparable 2013 period primarily due to $23.3 million of make-whole premiums paid to redeem the Series A Notes and Series B Notes (each as defined herein), as well as $16.4 million of premiums paid and non-cash deferred financing costs written off for the repurchase of $140.1 million aggregate principal amount of the 9.0% Notes in the first quarter of 2014.

*Foreign exchange gain*

Foreign exchange gain increased $10.9 million or 40% from the comparable 2013 period primarily due to a $7.4 million increase in unrealized gain in the revaluation of instruments denominated in Canadian dollars and a $18.4 million decrease in unrealized loss on foreign exchange forward contracts, offset by a $14.9 million decrease in realized gains on the settlement of foreign currency forward contracts. The U.S. dollar to Canadian dollar exchange rate was 1.16 and 1.06 at December 31, 2014 and 2013, respectively, an increase of 9.4% in 2014 compared to an increase of 6.9% in 2013.

*Other income, net*

Other income, net decreased $7.7 million or 73% from the 2013 comparable period primarily due to a $2.1 million non-cash gain recorded for the sale of Greeley in 2014 as compared to a $10.3 million gain and management fee agreement termination fee in 2013 resulting from the sale of Path 15.

*Income tax benefit*

Income tax benefit for the year ended December 31, 2014 was $11.9 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $50.4 million. The primary items impacting the tax rate for the year ended December 31, 2014 were $40.5 million relating to a change in the valuation allowance, $33.9 million relating to goodwill impairment, and $6.6 million relating to minority interest adjustments. These items were partially offset by $20.9 million relating to operating in higher tax rate jurisdictions, $10.2 million of capital losses recognized on tax restructuring, $7.4 million relating to foreign exchange, and $4.1 million relating to return to provision adjustments.

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***2013 compared to 2012***

The following tables and discussion summarize our consolidated results of operations and provide an analysis by reportable segment:

| | Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2013 | 2012 | $ change | % change |
| Project revenue: | | | | |
| Energy sales | $ 302.2 | $ 214.5 | $ 87.7 | 41% |
| Energy capacity revenue | 163.7 | 147.2 | 16.5 | 11% |
| Other | 78.2 | 68.1 | 10.1 | 15% |
| | 544.1 | 429.8 | 114.3 | 27% |
| Project expenses: | | | | |
| Fuel | 194.3 | 164.9 | 29.4 | 18% |
| Operations and maintenance | 150.8 | 119.6 | 31.2 | 26% |
| Development | 7.2 | | 7.2 | NM |
| Depreciation and amortization | 166.1 | 116.6 | 49.5 | 42% |
| | 518.4 | 401.1 | 117.3 | 29% |
| Project other income (expense): | | | | |
| Change in fair value of derivative instruments | 49.5 | (59.3) | 108.8 | NM |
| Equity in earnings of unconsolidated affiliates | 26.9 | 15.2 | 11.7 | 77% |
| Gain on sale of equity investments | 30.4 | 0.6 | 29.8 | NM |
| Interest expense, net | (34.4) | (16.4) | (18.0) | 110% |
| Impairment | (34.9) | | (34.9) | NM |
| Other income, net | 0.5 | | 0.5 | NM |
| | 38.0 | (59.9) | 97.9 | NM |
| Project income (loss) | 63.7 | (31.2) | 94.9 | NM |
| Administrative and other expenses (income): | | | | |
| Administration | 35.2 | 28.3 | 6.9 | 24% |
| Interest, net | 104.1 | 89.8 | 14.3 | 16% |
| Foreign exchange (gain) loss | (27.4) | 0.5 | (27.9) | NM |
| Other income, net | (10.5) | (5.7) | (4.8) | 84% |
| | 101.4 | 112.9 | (11.5) | 10% |
| Loss from continuing operations before income taxes | (37.7) | (144.1) | 106.4 | 74% |
| Income tax benefit | (19.5) | (28.1) | 8.6 | 31% |
| Loss from continuing operations | (18.2) | (116.0) | 97.8 | 84% |
| (Loss) income from discontinued operations, net of tax | (5.6) | 15.7 | (21.3) | NM |
| Net loss | (23.8) | (100.3) | 76.5 | 76% |
| Net loss attributable to noncontrolling interests | (3.4) | (0.6) | (2.8) | NM |
| Net income attributable to Preferred share dividends of a subsidiary company | 12.6 | 13.1 | (0.5) | 4% |
| Net loss attributable to Atlantic Power Corporation | $ (33.0) | $ (112.8) | $ 79.8 | 71% |

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***Project Income (Loss) by Segment***

| | Year Ended December 31, 2013 | | | | |
|---|---|---|---|---|---|
| | East[1] | West[2] | Wind | Un-allocated Corporate[3] | Consolidated Total |
| Project revenue: | | | | | |
| Energy sales | $ 150.1 | $ 81.6 | $ 70.6 | $ (0.1) | $ 302.2 |
| Energy capacity revenue | 118.3 | 45.6 | | (0.2) | 163.7 |
| Other | 30.7 | 47.5 | 0.2 | (0.2) | 78.2 |
| | 299.1 | 174.7 | 70.8 | (0.5) | 544.1 |
| Project expenses: | | | | | |
| Fuel | 135.0 | 59.2 | | 0.1 | 194.3 |
| Operations and maintenance | 63.7 | 55.5 | 20.8 | 10.8 | 150.8 |
| Development | | | | 7.2 | 7.2 |
| Depreciation and amortization | 68.9 | 54.9 | 41.8 | 0.5 | 166.1 |
| | 267.6 | 169.6 | 62.6 | 18.6 | 518.4 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | 25.5 | | 24.0 | | 49.5 |
| Equity in earnings of unconsolidated affiliates | 21.3 | 4.5 | 1.1 | | 26.9 |
| Gain on sale of equity investments | | 30.4 | | | 30.4 |
| Interest expense, net | (19.6) | (0.1) | (14.6) | (0.1) | (34.4) |
| Impairment | (30.8) | (4.1) | | | (34.9) |
| Other (expense) income, net | (2.1) | | (0.1) | 2.7 | 0.5 |
| | (5.7) | 30.7 | 10.4 | 2.6 | 38.0 |
| Project income (loss) | $ 25.8 | $ 35.8 | $ 18.6 | $ (16.5) | $ 63.7 |

| | Year Ended December 31, 2012 | | | | |
|---|---|---|---|---|---|
| | East[1] | West[2] | Wind | Un-allocated Corporate[3] | Consolidated Total |
| Project revenue: | | | | | |
| Energy sales | $ 143.7 | $ 70.8 | $ | $ | $ 214.5 |
| Energy capacity revenue | 98.7 | 46.6 | 1.9 | | 147.2 |
| Other | 25.1 | 41.6 | | 1.4 | 68.1 |
| | 267.5 | 159.0 | 1.9 | 1.4 | 429.8 |
| Project expenses: | | | | | |
| Fuel | 123.0 | 41.8 | 0.1 | | 164.9 |
| Operations and maintenance | 52.8 | 53.3 | 1.0 | 12.5 | 119.6 |
| Development | | | | | |
| Depreciation and amortization | 61.6 | 54.9 | | 0.1 | 116.6 |
| | 237.4 | 150.0 | 1.1 | 12.6 | 401.1 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | (59.3) | | | | (59.3) |
| Equity in earnings of unconsolidated affiliates | 27.5 | (4.1) | (8.2) | | 15.2 |
| Gain on sale of equity investment | | 0.6 | | | 0.6 |
| Interest expense, net | (16.4) | | | | (16.4) |
| | (48.2) | (3.5) | (8.2) | | (59.9) |

| | | | | | |
|---|---|---|---|---|---|
| Project income (loss) | $ (18.1) | $ 5.5 | $ (7.4) | $ (11.2) | $ (31.2) |

(1) Excludes the Florida Projects which are classified as discontinued operations.

(2) Excludes Path 15 and Greeley which are classified as discontinued operations.

(3) Excludes Rollcast which is designated as discontinued operations

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***East***

Project income for 2013 increased $43.9 million from 2012 primarily due to:

- increased project income from Kapuskasing of $37.4 million due primarily to a positive $35.8 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives;

- increased project income from North Bay of $35.2 million due primarily to a positive $35.8 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives;

- increased project income from Curtis Palmer of $4.0 million due primarily to increased generation resulting from higher water levels than the comparable period;

- increased project income from Calstock of $3.1 million due to increased capacity rates and generation, lower maintenance costs, and lower fuel costs than in the comparable 2012 period that had planned steam turbine maintenance; and

- increased project income from Nipigon of $2.6 million due primarily to higher availability and lower maintenance costs resulting from a planned outage in the comparable 2012 period.

These increases were partially offset by:

- decreased project income from Kenilworth of $27.2 million due primarily to a $30.8 million non-cash goodwill impairment charge recorded in the third quarter of 2013;

- decreased project income from Chambers of $6.2 million due primarily to the collection of the DuPont partial settlement associated with the dispute of the electricity price calculation under its PPA in the second quarter of 2012; and

- decreased project income from Tunis of $5.5 million due primarily to lower generation and energy prices.

Project income for the East segment excludes the Florida Projects as these projects were sold in April 2013, and are accounted for as a component of discontinued operations. Project loss for the Florida Projects was $1.1 million for the year ended December 31, 2013 as compared to project income of $13.6 million for the year ended December 31, 2012. The decrease is due primarily to the projects being sold in April 2013.

***West***

Project income for 2013 increased $30.3 million from 2012 primarily due to:

- increased project income from Gregory of $32.8 million primarily due to a $30.4 million gain on sale resulting from the project being sold in August 2013; and

- the sale of Badger Creek project in August in 2012 which had a $2.8 million project loss recorded in 2012.

These increases were partially offset by:

decreased project income of $3.7 million at Naval Station, Naval Training Center, and North Island due primarily to a $4.1 million non-cash goodwill impairment charge recorded in the third quarter of 2013; and

decreased project income from Mamquam of $3.5 million primarily attributable to increased maintenance costs from a scheduled outage and lower revenues due to lower water levels than the comparable period.

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Project income for the West segment excludes the Path 15 and Greeley projects which are accounted for as a component of discontinued operations. Project income for Path 15 was $2.1 million and $5.1 million for the years ended December 31, 2013 and 2012, respectively. The decrease is due primarily to the project being sold in April 2013. Project income for Greeley was $0.6 million and $1.8 million for the years ended December 31, 2013 and 2012, respectively. The decrease is due primarily to the project being sold in March 2014.

***Wind***

Project income for 2013 increased $26.0 million from 2012 primarily due to:

- increased project income from Rockland of $18.2 million attributable to the 100% consolidation of a former equity method project subsequent to an ownership change from 30% to 50% as part of the Ridgeline acquisition during the fourth quarter of 2012; and

- increased project income from Meadow Creek of $6.0 million which achieved commercial operations in December 2012. Meadow Creek was also part of the Ridgeline acquisition in December 2012. Meadow Creek's project income was primarily due to a positive $12.5 million non-cash change in the fair value of interest rate swap agreements that were accounted for as derivatives. This increase in income was offset by $8.1 million of interest expense.

***Un-allocated Corporate***

Total project loss increased $5.3 million from 2012 primarily due to $7.2 million of development expense at Ridgeline which was acquired in December 2012.

***Administrative and other expenses (income)***

Administrative and other expenses (income) include the income and expenses not attributable to our projects and are allocated to the Un-allocated Corporate segment. These costs include the activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate tax. Significant non-cash items that impact Administrative and other expenses (income), which are subject to potentially significant fluctuations, include the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar-denominated obligations and the related deferred income tax expense (benefit) associated with these non-cash items.

*Administration*

Administration expense increased $6.9 million or 24% from 2012 primarily due to transactional fees during 2013 related to divestitures, the shareholder class action lawsuits and the amendment of the Prior Credit Facility in August as well as an increase in salaries and severance expenses.

*Interest, net*

Interest expense increased $14.3 million or 16% from 2012 primarily due to the issuance of the $130 million principal amount of convertible debentures in July of 2012 and issuance of the Cdn$100 million principal amount of convertible debentures in December of 2012 as well as interest related to the Prior Credit Facility.

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*Foreign exchange loss (gain)*

Foreign exchange gain increased $27.9 million primarily due to a $39.4 million increase in unrealized gain in the revaluation of instruments denominated in Canadian dollars, offset by a $4.1 million decrease in realized gains on the settlement of foreign currency forward contracts and a $7.4 million increase in unrealized loss on foreign exchange forward contracts. The U.S. dollar to Canadian dollar exchange rate was 1.0636 and 0.9949 at December 31, 2013 and 2012, respectively, an increase of 6.9% in 2013 compared to a decrease of 2.2% in 2012.

*Other income, net*

Other income, net increased $4.8 million or 84% from 2012 period primarily due to a $10.3 million gain on sale and management agreement termination fee resulting from the sale of Path 15. In 2012, we recorded a $6.0 million management agreement termination fee related to the sale of our equity interest in PERH.

*Income tax benefit*

Income tax benefit for the year ended December 31, 2013 was $19.5 million. Income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $9.7 million. The primary items impacting the effective tax rate relate to a benefit of $18.9 million from the 1603 Treasury Grants received in 2013, a $9.9 million benefit relating to foreign exchange differences, and $4.5 million related to production tax credits. These benefits were offset by a $12.1 million additional tax expense related to a change in the valuation allowance and an additional $13.6 million tax expense related to the goodwill impairment charge during 2013.

**Project Operating Performance**

Two of the primary metrics we utilize to measure the operating performance of our projects are generation and availability. Generation measures the net output of our proportionate project ownership percentage in megawatt hours. Availability is calculated by dividing the total scheduled hours of a project less forced outage hours by the total hours in the period measured. The terms of our PPAs require our projects to maintain certain levels of availability. The majority of our projects were able to achieve substantially all of their respective capacity payments. For projects where reduced availability adversely impacted capacity payments, the impact was approximately $10.3 million for the year ended December 31, 2014. The terms of our PPAs provide for certain levels of planned and unplanned outages.

***Generation***

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| **(in Net MWh)** | **2014** | **2013** | **2012** | **% change 2014 vs. 2013** | **% change 2013 vs. 2012** |
| **Segment** | | | | | |
| East[(1)] | 3,966.2 | 3,889.0 | 3,533.4 | 2.0% | 10.1% |
| West[(2)] | 2,432.8 | 2,455.9 | 2,006.9 | 0.9% | 22.4% |
| Wind | 1,800.3 | 1,749.6 | 221.7 | 2.9% | NM |
| Total | 8,199.3 | 8,094.5 | 5,762.0 | 1.3% | 40.5% |

(1) Excludes the Florida Projects which are classified as discontinued operations.

(2) Excludes (i) Delta-Person, which was sold in July 2014, (ii) Gregory, which was sold in August 2013 and (iii) Greeley, which was sold in March 2014 and is designated as discontinued operations.

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*Year ended December 31, 2014 compared with Year ended December 31, 2013*

Aggregate power generation for 2014 increased 1.3% from 2013 primarily due to:

increased generation in the East segment due to a 123.5 net MWh increase in generation at Piedmont, which achieved commercial operations in April 2013, resulting in an additional quarter of generation in 2014, and a 45.4 MWh increase in generation at Orlando which was due to the expiration of an unfavorable natural gas contract in the comparable 2013 period, partially offset by a 151.6 net MWh decrease at Selkirk due to mild summer weather resulting in lower dispatch for the 2014 period; and

increased generation in the Wind segment due to a 64.5 net MWh increase resulting from favorable winds at Meadow Creek.

Generation did not change materially in our West segment for the year ended December 31, 2014.

*Year ended December 31, 2013 compared with Year ended December 31, 2012*

Aggregate power generation for 2013 increased 40.5% from 2012 primarily due to:

increased generation in the East segment due to Piedmont, which achieved commercial operations in April 2013;

increased generation in the West segment due to increased dispatch at Manchief and higher generation at Frederickson; and

increased generation in the Wind segment primarily due to Canadian Hills which achieved commercial operations in December 2012 and Meadow Creek, which was acquired as part of the Ridgeline acquisition in December 2012.

***Availability***

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | % change 2014 vs. 2013 | % change 2013 vs. 2012 |
| **Segment** | | | | | |
| East[1] | 93.6% | 95.6% | 96.3% | 2.1% | 0.7% |
| West[2] | 91.7% | 91.8% | 93.1% | 0.1% | 1.4% |
| Wind | 96.8% | 98.7% | 98.6% | 1.9% | 0.1% |
| Weighted average | 93.4% | 94.8% | 95.3% | 1.5% | 0.5% |

(1) Excludes the Florida Projects which are classified as discontinued operations.

(2) Excludes (i) Delta-Person, which was sold in July 2014, (ii) Gregory, which was sold in August 2013 and (iii) Greeley, which was sold in March 2014 and is designated as discontinued operations.

Weighted average availability for 2014 decreased 1.5% to 93.4% from 2013 primarily due to:

decreased availability in the East segment resulting from decreased availability at Nipigon, Chambers, and Orlando, each of which experienced planned maintenance outages in the year ended December 31, 2014; and decreased availability in the Wind segment due to Canadian Hills, which underwent a weather-related outage in the first quarter of 2014.

Availability did not change materially in our West segment for the year ended December 31, 2014.

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*Year ended December 31, 2013 compared with Year ended December 31, 2012*

Weighted average availability for 2013 decreased 0.5% to 94.8% from 2012 primarily due to:

- decreased availability in the West segment resulting from decreased availability at Mamquam and Moresby Lake, which underwent scheduled maintenance during 2013; and

- decreased availability in the East segment resulting from decreased availability at Morris, which underwent scheduled maintenance during 2013.

This decrease was partially offset by:

- increased availability in the Wind segment resulting from increased availability at Meadow Creek and Goshen, which were acquired in December 2012, as well as increased availability at Canadian Hills, which achieved commercial operations in December 2012.

Generation and availability statistics for the East segment exclude the Florida Projects which are accounted for as a component of discontinued operations. Total generation for Auburndale was 916.5 MWh and availability was 94.8% for the year ended December 31, 2012. Total generation for Lake was 588.9 MWh and availability was 99.2% for the year ended December 31, 2012. Total generation for Pasco was 252.0 MWh and availability was 96.1% for the year ended December 31, 2012. Generation and availability statistics for the West segment exclude Greely, Delta-Person and Gregory, the totals of which are immaterial.

***Supplementary Non-GAAP Financial Information***

A key measure we use to evaluate the results of our business is Free Cash Flow. Free Cash Flow is not a measure recognized under GAAP, does not have a standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures presented by other issuers. We believe Free Cash Flow is a relevant supplemental measure of our ability to pay for additional debt reduction, fund internal or external growth, pay any dividends to our shareholders, or many other allocations of any available cash. A reconciliation of Free Cash Flow to cash flows from operating activities, the most directly comparable GAAP measure, is set out below under "Free Cash Flow." Free Cash Flow is comparable to Cash Available for Distribution, the non-GAAP measure we previously used to evaluate the results of our business. Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

The primary factor influencing Free Cash Flow is cash distributions received from projects. These distributions are generally funded from Project Adjusted EBITDA generated by the projects, reduced by project-level debt service, capital expenditures, dividends paid on preferred shares of a subsidiary company, distributions to noncontrolling interests and adjusted for changes in project-level working capital and cash reserves. Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. A reconciliation of Project Adjusted EBITDA to project income (loss) is provided under "Project Adjusted EBITDA" below and a reconciliation of Project Adjusted EBITDA by segment to project income (loss) by segment is provided in Note 22 to the consolidated financial statements of this Annual Report on Form 10-K. Project Adjusted EBITDA for our equity investments in unconsolidated affiliates is presented on a proportionately consolidated basis in the table below. Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

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**Project Adjusted EBITDA**

| | Year ended December 31, | | | $ change | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2014 | 2013 |
| **Project Adjusted EBITDA by segment** | | | | | |
| East[1] | $ 158.5 | $ 150.7 | $ 145.7 | $ 7.8 | $ 5.0 |
| West[2] | 78.5 | 77.2 | 78.9 | 1.3 | (1.7) |
| Wind | 69.8 | 59.6 | 10.9 | 10.2 | 48.7 |
| Un-allocated Corporate[3] | (7.5) | (18.6) | (11.1) | 11.1 | (7.5) |
| **Total** | 299.3 | 268.9 | 224.4 | 30.4 | 44.5 |
| **Reconciliation to project income** | | | | | |
| Depreciation and amortization | 201.7 | 208.8 | 163.5 | (7.1) | 45.3 |
| Interest expense, net | 39.5 | 38.5 | 24.0 | 1.0 | 14.5 |
| Change in the fair value of derivative instruments | 10.4 | (50.3) | 56.6 | 60.7 | (106.9) |
| Impairment and other expense | 98.2 | 8.2 | 11.5 | 90.0 | (3.3) |
| **Project (loss) income** | $ (50.5) | $ 63.7 | $ (31.2) | $ (114.2) | $ 94.9 |

(1) Excludes the Florida Projects which are classified as discontinued operations.

(2) Excludes Path 15 and Greeley which are classified as discontinued operations.

(3) Excludes Rollcast which is classified as discontinued operations.

*East*

The following table summarizes Project Adjusted EBITDA for our East segment for the periods indicated:

| | Year ended December 31, | | | % change 2014 vs. 2013 | % change 2013 vs. 2012 |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | | |
| **East** | | | | | |
| Project Adjusted EBITDA | $ 158.5 | $ 150.7 | $ 145.7 | 5% | 3% |

*Year ended December 31, 2014 compared with Year ended December 31, 2013*

Project Adjusted EBITDA for 2014 increased $7.8 million or 5% from 2013 primarily due to increases in Project Adjusted EBITDA of:

- $6.3 million at Morris due primarily to a $14.4 million increase in energy revenues. Energy payments were escalated under the terms of the project's PPA due to higher natural gas prices. This increase was partially offset by higher fuel expenses compared to the 2013 period;

- $6.3 million at Orlando primarily attributable to increased generation and higher energy revenues due to a change in revenue escalators in the amended off-taker contract as well as lower fuel expenses than the comparable 2013 period. Orlando operated under an above-market fuel agreement that expired in the fourth quarter of 2013;

$4.4 million at Piedmont due primarily to $7.0 million of increased revenues offset by $3.5 million of increased fuel expense resulting from a full year of operation in 2014 as compared to the eight months in 2013 when it became commercially operational in April 2013; and

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$2.5 million at Kapuskasing, $2.3 million at North Bay, and $2.1 million at Nipigon due to lower maintenance costs and increased energy revenue resulting from higher waste heat generation than the comparable 2013 period.

These increases were partially offset by decreases in Project Adjusted EBITDA of:

$10.5 million at Selkirk primarily attributable to lower energy revenue resulting from decreased generation due to lower dispatch from mild weather conditions during the 2014 period and expiration of its PPA in August 2014;

$2.0 million at Chambers due to increased maintenance costs, partially offset by higher energy revenues resulting from increased dispatch than in the comparable 2013 period;

$1.5 million at Kenilworth primarily attributable to lower steam revenue resulting from lower steam prices in the comparable 2013 period; and

$1.3 million at Cadillac due to increased maintenance expenses resulting from a scheduled turbine maintenance outage in the 2014 period.

Project Adjusted EBITDA for the East segment excludes the Florida Projects as these projects were sold in April 2013, and are accounted for as a component of discontinued operations. Project Adjusted EBITDA for the Florida Projects was $27.2 million for the year ended December 31, 2013.

*Year ended December 31, 2013 compared with Year ended December 31, 2012*

Project Adjusted EBITDA for 2013 increased $5.0 million or 3% from 2012 primarily due to increases in Project Adjusted EBITDA of:

$4.0 million at Curtis Palmer primarily attributable to increased generation resulting from higher water levels than the comparable period and a $2.0 million favorable water reclamation tax assessment during 2013;

$3.6 million at Kenilworth primarily attributable to increased capacity revenues under the renewal of the project's energy service agreement;

$3.0 million at Calstock which had a steam turbine maintenance outage occur in the comparable 2012 period and contractual escalation of capacity rates in the 2013 period;

$3.0 million at Selkirk due to energy revenues resulting from higher generation, partially offset by higher fuel costs; and

$2.4 million at Kapuskasing primarily attributable to a steam turbine maintenance outage that occurred in the comparable 2012 period.

These increases were partially offset by decreases in Project Adjusted EBITDA of:

$7.2 million at Chambers primarily attributable to the collection of the DuPont partial settlement associated with the dispute of the electricity price calculation in the comparable 2012 period; and

$4.0 million at Tunis resulting from lower generation and higher maintenance costs due to a scheduled maintenance outage.

Project Adjusted EBITDA for the East segment excludes the Florida Projects as these projects were sold in April 2013, and are accounted for as a component of discontinued operations. Project Adjusted EBITDA for the Florida Projects was $27.2 million for the year ended December 31, 2013 as compared to $82.4 million for the year ended December 31, 2012.

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*West*

The following table summarizes Project Adjusted EBITDA for our West segment for the periods indicated:

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | % change 2014 vs. 2013 | % change 2013 vs. 2012 |
| **West** | | | | | |
| Project Adjusted EBITDA | $ 78.5 | $ 77.2 | $ 78.9 | 2% | 2% |

*Year ended December 31, 2014 compared with Year ended December 31, 2013*

Project Adjusted EBITDA for 2014 increased by $1.3 million or 2% from 2013 primarily due to increases in Project Adjusted EBITDA of:

$3.8 million at Naval Training Center which underwent a scheduled turbine maintenance outage in the comparable 2013 period; and

$3.6 million at Mamquam due to $0.9 million in higher revenues resulting from increased water flows as well as a $2.5 million decrease in maintenance expense compared to the 2013 period, during which the project underwent turbine maintenance.

These increases were partially offset by decreases in Project Adjusted EBITDA of:

$3.2 million at Gregory and Delta-Person, which were sold in August 2013 and July 2014, respectively;

$2.2 million at Oxnard attributable to higher maintenance costs due to scheduled turbine maintenance than in the comparable 2013 period; and

$2.0 million at Manchief attributable to lower dispatch than the comparable 2013 period.

Project Adjusted EBITDA for the West segment excludes the Path 15 and Greeley projects which are accounted for as components of discontinued operations. Project Adjusted EBITDA for Path 15 was $9.0 million for the year ended December 31, 2013. Project Adjusted EBITDA for Greeley was $0.1 million and $1.5 million for the years ended December 31, 2014 and 2013, respectively. The decrease is due to the project being sold during the first quarter of 2014.

*Year ended December 31, 2013 compared with Year ended December 31, 2012*

Project Adjusted EBITDA for 2013 decreased by $1.7 million or 2% from 2012 primarily due to decreases in Project Adjusted EBITDA of:

$3.4 million at Mamquam resulting from higher maintenance costs due to a scheduled outage and decreased revenues caused by lower water levels; and

$2.2 million at Williams Lake due to lower energy revenues from contractual price decreases and higher maintenance costs than the comparable 2012 period.

Project Adjusted EBITDA for the West segment excludes the Path 15 project which is accounted for as a component of discontinued operations. Project Adjusted EBITDA for Path 15 was $9.0 million and $24.5 million for the years ended December 31, 2013 and 2012, respectively. The decrease is due to the project being sold during the second quarter of 2013. Project Adjusted EBITDA for Greeley was $1.5 million and $3.2 million for the years ended December 31, 2014 and 2013, respectively. The decrease is due to the projects PPA expiring during the third quarter of 2013.

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*Wind*

The following table summarizes Project Adjusted EBITDA for our Wind segment for the periods indicated:

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | % change 2014 vs. 2013 | % change 2013 vs. 2012 |
| **Wind** | | | | | |
| Project Adjusted EBITDA | $ 69.8 | $ 59.6 | $ 10.9 | 17% | NM |

*Year ended December 31, 2014 compared with Year ended December 31, 2013*

Project Adjusted EBITDA for 2014 increased by $10.2 million or 17% from 2013 primarily due to increases in Project Adjusted EBITDA of:

- $5.3 million at Meadow Creek, $2.0 million at Rockland, and $1.0 million at Canadian Hills primarily attributable to higher generation than in the comparable 2013 period.

*Year ended December 31, 2013 compared with Year ended December 31, 2012*

Project Adjusted EBITDA for 2013 increased by $48.7 million from 2012 primarily due to increases in Project Adjusted EBITDA of:

- $24.8 million at Canadian Hills which achieved commercial operations in December 2012;
- $14.0 million at Meadow Creek which was part of the Ridgeline acquisition and achieved commercial operations in December 2012;
- $6.8 million at Rockland attributable to the 100% consolidation of a former equity method project subsequent to an ownership change from 30% to 50% as part of the Ridgeline acquisition in December 2012; and
- $3.0 million at Goshen which was acquired as part of the Ridgeline acquisition in December 2012.

*Un-allocate Corporate*

The following table summarizes Project Adjusted EBITDA for our Un-allocated Corporate segment for the periods indicated:

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | % change 2014 vs. 2013 | % change 2013 vs. 2012 |
| **Un-allocated Corporate** | | | | | |
| Project Adjusted EBITDA | $ (7.5) | $ (18.6) | $ (11.1) | 60% | 68% |

*Year ended December 31, 2014 compared with Year ended December 31, 2013*

Project Adjusted EBITDA for 2014 increased by $11.1 million or 60% from the comparable 2013 period primarily due to decreased development costs at Ridgeline, which was acquired in December 2012, and a decrease in administrative costs related to administrative and development reduction initiatives undertaken during the year ended December 31, 2014.

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*Year ended December 31, 2013 compared with Year ended December 31, 2012*

Project Adjusted EBITDA for 2013 decreased by $7.5 million from 2012 primarily due to $7.2 million of administrative and development costs at Ridgeline which was acquired in December 2012.

**Free Cash Flow**

Free Cash Flow was ($55.6) million, $108.8 million, and $131.6 million for the years ended December 31, 2014, 2013, and 2012, respectively. Debt repayments of $58.4 million on the Partnership's term loan facility, increased project debt repayment of $10.6 million and increased purchases of property, plant and equipment of $6.9 million together with an $87.4 million reduction in cash flows from operations contributed to the decrease in Free Cash Flow. The net reduction of $87.4 million in cash flows from operations is due to interest expense related to the debt repayment and repurchase transactions in the first quarter of 2014, changes in working capital and the loss of cash flows from businesses that were divested in 2013.

The $22.8 million decrease in Free Cash Flow for the year ended December 31, 2013 as compared to the same period in 2012 was positively impacted by the reduced cash dividends declared to shareholders as well as the inclusion of operating results from Canadian Hills and Meadow Creek, which achieved commercial operations in late December 2012. This was partially offset by lower operating cash flows as a result of the sale of the Florida Projects and Path 15 in April 2013. The decrease in cash flows from operating activities is discussed in-depth in the "Consolidated Cash Flows" section below.

The table below presents our calculation of Free Cash Flow for the years ended December 31, 2014, 2013, and 2012, and the reconciliation to cash flows from operating activities, the most directly comparable GAAP measure:

| | Years ended December 31, | | |
|---|---|---|---|
| | **2014** | **2013** | **2012** |
| Cash flows from operating activities | $ 65.0 | $ 152.4 | $ 167.1 |
| Term loan facility repayments[(1)] | (58.4) | | |
| Project-level debt repayments | (26.2) | (15.6) | (19.6) |
| Purchases of property, plant and equipment[(2)] | (13.4) | (6.5) | (2.9) |
| Distributions to noncontrolling interests[(3)] | (11.0) | (8.9) | |
| Dividends on preferred shares of a subsidiary company | (11.6) | (12.6) | (13.0) |
| Free Cash Flow[(4)] | $ (55.6) | $ 108.8 | $ 131.6 |

(1) Includes mandatory 1% annual amortization and 50% excess cash flow repayments by the Partnership under the Senior Secured Credit Facilities (as defined herein).

(2) Excludes construction costs related to our Canadian Hills and Piedmont projects in 2014 and our Canadian Hills, Piedmont and Meadow Creek projects in 2013.

(3) Distributions to noncontrolling interests include distributions to the tax equity investors at Canadian Hills and to the other 50% owner of Rockland.

(4) Free Cash Flow is not a recognized measure under GAAP and does not have any standardized meaning prescribed by GAAP. Therefore, this measure may not be comparable to similar measures presented by other companies. See "Supplementary Non-GAAP Financial Information" above. This table should be read together with the below table under "Consolidated Cash Flows" that sets forth Net cash provided by (used in) investing activities and Net cash (used in) provided by financing activities for the years ended December 31, 2014, 2013, and 2012.

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**Consolidated Cash Flows**

The following table reflects the changes in cash flows for the periods indicated:

| | Year ended December 31, 2014 | Year ended December 31, 2013 | Change |
|---|---|---|---|
| Net cash provided by operating activities | $ 65.0 | $ 152.4 | $ (87.4) |
| Net cash provided by investing activities | 68.7 | 147.1 | (78.4) |
| Net cash used in financing activities | (182.4) | (207.6) | 25.2 |

***Operating Activities***

Cash flow from our projects may vary from year to year based on working capital requirements and the operating performance of the projects, as well as changes in prices under PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, and the transition to merchant or re-contracted pricing following the expiration of PPAs. Project cash flows may have some seasonality and the pattern and frequency of distributions to us from the projects during the year can also vary, although such seasonal variances do not typically have a material impact on our business.

Cash flow from operating activities decreased $87.4 million for the year ended December 31, 2014 from the comparable period in 2013. The decrease in cash flows from operating activities is primarily due to (i) $46.8 million of interest expense related to make-whole, accrued interest and premium payments made in connection with the redemption of the Series A Notes, the Series B Notes, and the Curtis Palmer Notes (each as defined herein) and the repurchase of $140.1 million aggregate principal amount of the 9.0% Notes in the first quarter of 2014, (ii) a decrease in cash flows from operating activities from the Florida Projects and Path 15, which were sold in 2013 and (iii) a $65.7 million increase in cash outflows for working capital. The decrease in cash flows from working capital is primarily due to a $39.4 million decrease in working capital from the 2013 collection of security deposits related to our completed construction projects, such as Piedmont, Canadian Hills and Meadow Creek.

***Investing Activities***

Cash flow from investing activities includes changes in restricted cash. Restricted cash fluctuates from period to period in part because certain of our non-recourse project-level financing arrangements require all operating cash flow from the project to be deposited in restricted accounts and then released at the time that principal payments are made and project-level debt service coverage ratios are met. As a result, the timing of principal payments on certain of our project-level debt causes significant fluctuations in restricted cash balances, which typically benefits investing cash flow in the second and fourth quarters of the year and decreases investing cash flow in the first and third quarters of the year.

Cash flows provided by investing activities for the year ended December 31, 2014 were $68.7 million compared to cash flows provided by investing activities of $147.1 million for the year ended December 31, 2013. The change is due to $182.6 million in cash received for the sale of the Florida Projects, Path 15 and Gregory projects during the 2013 period, $103.2 million in treasury grant proceeds received for Meadow Creek and Piedmont in the year ended December 31, 2013, partially offset by a $166.3 million increase in the change in restricted cash primarily due to the release of the $75.0 million requirement under the prior credit facility, and a $39.3 million decrease of cash used in construction costs related to the Piedmont and Canadian Hills projects, which both completed construction and achieved commercial operations during 2013.

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***Financing Activities***

Cash used in financing activities for the year ended December 31, 2014 resulted in a net outflow of $182.4 million compared to a net outflow of $207.6 million for the comparable 2013 period. The change from the prior year is due to a $79.0 million increase in net proceeds and payments on project-level and corporate debt attributable to the proceeds from the Senior Secured Credit Facilities (as defined herein) offset by repayments of the Series A Notes and Series B Notes and the Curtis Palmer Notes, and the repurchase of $140.1 million aggregate principal amount of the 9.0% Notes in the first quarter of 2014, $67.0 million decrease in payments for our revolving credit facility borrowings, offset partially by a $44.6 million decrease in equity contributions from noncontrolling interests at Canadian Hills received during the comparable 2013 period, a $36.2 million increase in deferred financing costs primarily due to the issuance of the Senior Secured Credit Facility in the first quarter of 2014, and a $20.8 million decrease in proceeds from project-level debt.

**Liquidity and Capital Resources**

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Cash and cash equivalents | $ 109.9 | $ 158.6 |
| Restricted cash[1] | 41.6 | 114.2 |
| Total | 151.5 | 272.8 |
| Revolving credit facility availability | 104.3 | 52.8 |
| Total liquidity | $ 255.8 | $ 325.6 |

(1) The decrease in restricted cash is primarily due to the release of the $75.0 million reserve requirement under the prior credit facility.

Our primary source of liquidity is distributions from our projects and availability under our Revolving Credit Facility. Our liquidity depends in part on our ability to successfully enter into new PPAs at projects when PPAs expire or terminate. PPAs in our portfolio have expiration dates ranging from December 31, 2017 to December 31, 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. As a result, this may reduce the cash received from project distributions and the cash available for further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, and other allocation of available cash. See "Risk Factors Risks Related to Our Structure We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or implement our business plan, including financing external growth opportunities or fund our operations."

We expect to reinvest approximately $35.0 million in our portfolio in the form of project capital expenditures and maintenance expenses in 2015. Such investments are generally paid at the project level. See " Capital and Major Maintenance Expenditures." We do not expect any other material or unusual requirements for cash outflow in 2015 for capital expenditures or other required investments. We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due for at least the next 12 months.

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***Corporate Debt Service Obligations***

The following table summarizes the maturities of our corporate debt at December 31, 2014:

| | Maturity Date | Interest Rates | Remaining Principal Repayments | 2015 | 2016 | 2017 | 2018 | 2019 | Thereafter |
|---|---|---|---|---|---|---|---|---|---|
| Senior Secured Term Loan Facility[1] | February 2021 | 4.75%-5.90% | $ 541.5 | $ 5.4 | $ 5.4 | $ 5.4 | $ 5.4 | $ 5.4 | $ 514.5 |
| Atlantic Power Corporation Notes[2] | November 2018 | 9.0% | 319.9 | | | | 319.9 | | |
| Atlantic Power Income LP Note | June 2036 | 6.0% | 181.0 | | | | | | 181.0 |
| Convertible Debenture | March 2017 | 6.3% | 58.0 | | | 58.0 | | | |
| Convertible Debenture | June 2017 | 5.6% | 68.7 | | | 68.7 | | | |
| Convertible Debenture | June 2019 | 5.8% | 128.2 | | | | | 128.2 | |
| Convertible Debenture | December 2019 | 6.0% | 85.7 | | | | | 85.7 | |
| Total Corporate Debt | | | $ 1,383.0 | $ 5.4 | $ 5.4 | $ 132.1 | $ 325.3 | $ 219.3 | $ 695.5 |

(1) In addition to the annual principal payments described herein, the Credit Agreement requires payment of 50% of the excess cash flow of the Partnership and its subsidiaries.

(2) We repurchased and cancelled $9.0 million principal of the Atlantic Power Corporation Notes in January 2015, reducing the outstanding total to $310.9 million as of February 21, 2015.

***Senior Secured Credit Facilities***

On February 24, 2014, the Partnership, our wholly-owned indirect subsidiary, entered into the a new senior secured term loan facility (the "Term Loan Facility"), comprising $600 million in aggregate principal amount, and a new senior secured revolving credit facility (the "Revolving Credit Facility") with a capacity of $210 million (collectively, the "Senior Secured Credit Facilities"). Borrowings under the Senior Secured Credit Facilities are available in U.S. dollars and Canadian dollars and bear interest at a rate equal to the Adjusted Eurodollar Rate, the Base Rate or the Canadian Prime Rate, each as defined in the credit agreement governing the Senior Secured Credit Facilities (the "Credit Agreement"), as applicable, plus an applicable margin between 2.75% and 3.75% that varies depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. The applicable margin for term loans bearing interest at the Adjusted Eurodollar Rate and the Base Rate is 3.75% and 2.75% respectively (3.75% at February 21, 2015). The Adjusted Eurodollar Rate cannot be less than 1.00% (1.00% at February 21, 2015).

In connection with the funding of the Senior Secured Credit Facilities, we terminated our prior revolving credit facility on February 26, 2014.

The Term Loan Facility matures on February 24, 2021. The revolving commitments under the Revolving Credit Facility terminate on February 24, 2018. Letters of credit are available to be issued under the revolving commitments until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. The Partnership is required to pay a commitment fee with respect to the commitments under the Revolving Credit Facility equal to 0.75% times the average of the daily difference between the revolving commitments and all outstanding revolving loans (excluding swing line loans) plus amounts available to be drawn under letters of credit and all outstanding reimbursement obligations with respect to drawn letters of credit.

The Senior Secured Credit Facilities are secured by a pledge of the equity interests in the Partnership and its subsidiaries, guaranties from the Partnership subsidiary guarantors and a limited recourse guaranty from the entity that holds all of the Partnership equity, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of the Partnership and its subsidiaries (subject to certain exceptions), and certain other assets. The Senior Secured Credit Facilities are not otherwise guaranteed or secured by us or any of our subsidiaries (other than the Partnership subsidiary guarantors). The Senior Secured Credit Facilities

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also have a debt service reserve account, which is required to be funded and maintained at the debt service reserve requirement, equal to six months of debt service. The debt service reserve requirement was funded with a $15.8 million letter of credit.

The Partnership's existing Cdn$210 million aggregate principal amount of 5.95% Medium Term Notes due June 23, 2036 (the "MTNs") prohibit the Partnership (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries) to secure indebtedness, unless the MTNs are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, the Partnership granted an equal and ratable security interest in the collateral package securing the Senior Secured Credit Facilities under the indenture governing the MTNs for the benefit of the holders of the MTNs.

The Credit Agreement contains customary representations, warranties, terms and conditions, and covenants. The covenants include a requirement that the Partnership and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 5.25:1.00 in 2014 to 4.00:1.00 in 2021, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 2.50:1.00 in 2014 to 3.25:1.00 in 2021. In addition, the Credit Agreement includes customary restrictions and limitations on the Partnership's and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v) modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case subject to customary carve-outs and exceptions and various thresholds.

Under the Credit Agreement, if a change of control (as defined in the Credit Agreement) occurs, unless the Partnership elects to make a voluntary prepayment of the term loans under the Senior Secured Credit Facilities, it will be required to offer each electing lender to prepay such lender's term loans under the Senior Secured Credit Facilities at a price equal to 101% of par. In addition, in the event that the Partnership elects to repay, prepay or refinance all or any portion of the term loan facilities within one year from the initial funding date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid or refinanced.

The Credit Agreement contains a mandatory amortization feature and customary mandatory prepayment provisions, including: (i) from proceeds of assets sales, insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and (ii) the payment of 50% of the excess cash flow, as defined in the Credit Agreement, of the Partnership and its subsidiaries.

Under certain conditions the lending commitments under the Credit Agreement may be terminated by the lenders and amounts outstanding under the Credit Agreement may be accelerated. Such events of default include failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations or warranties in any material respect, non-payment or acceleration of other material debt of the Partnership and its subsidiaries, bankruptcy, material judgments rendered against the Partnership or certain of its subsidiaries, certain ERISA or regulatory events, a change of control of the Partnership, or defaults under certain guaranties and collateral documents securing the Senior Secured Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

On February 26, 2014, $600 million was drawn under the Term Loan Facility, and letters of credit in an aggregate face amount of $144.1 million ($108.3 million as of February 21, 2015) were issued (but not drawn) pursuant to the revolving commitments under the Revolving Credit Facility and used to (i) satisfy a debt service reserve requirement in an amount equivalent to six months of debt service (approximately $15.8 million) and (ii) support contractual credit support obligations of the Partnership and its subsidiaries and of certain other of our affiliates.

We and our subsidiaries used the proceeds from the Term Loan Facility under the Senior Secured Credit Facilities to:

- redeem in whole, at a price equal to par plus $31.1 million of accrued interest and make-whole premiums (i) the $150 million aggregate principal amount outstanding of the Series A Notes (the "Series A Notes") and the $75 million aggregate principal amount outstanding of the Series B Notes (the "Series B Notes") issued by Atlantic Power (US) GP, and (ii) the $190 million aggregate principal amount outstanding of 5.9% Senior Notes due 2014 issued by Curtis Palmer LLC (the "Curtis Palmer Notes");

- pay transaction costs and expenses of approximately $40.0 million including banking, legal and consulting fees which were capitalized as deferred financing costs; and

- make a distribution to us in the amount of $122 million which was used, in addition to cash on hand, to repurchase $140.1 million aggregate principal amount of the 9.0% Notes, make $15.7 million in accrued interest and premium payments as part of the aggregate repurchase price, and $0.1 million in commission fees associated with the repurchases.

In connection with the termination of our prior credit facility, we terminated the interest rate swap at Epsilon Power Partners, a wholly owned subsidiary, a portion of our natural gas swaps at Orlando and foreign exchange forward contracts at the Partnership. As a result of the termination of these contracts, we recorded $2.6 million of interest expense, $4.0 million of fuel expense and $0.4 million of foreign exchange loss, respectively.

In addition, the prior credit facility contained certain guaranties, which were terminated in connection with the termination of the prior credit facility. In addition, the terms of the 9.0% Notes provide that the guarantors of the prior credit facility guarantee the 9.0% Notes. As a result, upon termination of our prior credit facility and its related guaranties, the guaranties under the 9.0% Notes were cancelled and the guarantors of the 9.0% Notes were automatically released from all of their obligations under such guaranties.

*Impact of the Senior Secured Credit Facilities*

As previously disclosed in our Current Report on Form 8-K filed on January 30, 2014 and in our Annual Report on Form 10-K for the year ended December 31, 2013, due to the aggregate impact of the up-front costs resulting from the prepayments on our indebtedness described above, including the premium payment and charges for unamortized debt discount and fee expenses and premiums as part of the overall purchase price in respect of the repurchases of the 9.0% Notes (all such up-front costs, collectively, the "Prepayment Charges"), which were reflected as interest expense in our 2014 first quarter results, we no longer satisfy the fixed charge coverage ratio test included in the restricted payments covenant of the indenture governing the 9.0% Notes. The fixed charge coverage ratio must be at least 1.75 to 1.00 and is measured on a rolling four quarter basis, including after giving effect to certain pro forma adjustments.

As a consequence, further dividend payments, which are declared and paid at the discretion of our board of directors, in the aggregate cannot exceed the covenant's "basket" provision of the greater of $50 million and 2% of consolidated net assets (approximately $55.8 million at December 31, 2014) until such time that we satisfy the fixed charge coverage ratio test. We have declared dividends in 2014, totaling approximately $32.5 million that were subject to the basket provision. For the trailing twelve months ended December 31, 2014, dividend payments to our shareholders totaled approximately Cdn$46.7 million. In September 2014, we adjusted our dividend to Cdn$0.03 per common share to be paid quarterly based on an annual dividend payment of Cdn$0.12 per common share, with the first quarterly dividend declared in November and paid at the end of December 2014. No dividends were declared in September 2014. Dividends to shareholders are paid, if and when declared by, and subject to the discretion of, the Board of Directors.

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The Prepayment Charges would no longer be reflected in the calculation of the fixed charge coverage ratio test after the passage of four additional successive quarters following the quarter in which the Prepayment Charges are incurred. In addition, any similar prepayment charges incurred in connection with any further debt reduction would also be reflected in the calculation of the fixed charge coverage ratio test on a rolling four quarter basis, beginning with the quarter in which such charges are incurred, as would any associated reduction in interest expense. We expect to satisfy the fixed charge ratio test in the first half of 2015.

Separately, we expect to be in compliance with the financial maintenance covenants in the agreements governing our indebtedness for at least the next twelve months.

***Project-Level Debt Service Obligations***

Project-level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at December 31, 2014. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project-level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. See Note 11, *Long-term debt.* Although all of our projects with non-recourse loans are currently meeting their debt service requirements, we cannot provide any assurances that our projects will generate enough future cash flow to meet any applicable ratio tests in order to be able to make distributions to us. Currently we do not expect our Piedmont project to meet its debt service coverage ratio covenants or to make distributions before 2017 at the earliest, due to continued operational issues that have resulted in higher forecasted maintenance and fuel expenses than initially expected.

*Non-Recourse Debt*

The range of interest rates presented represents the rates in effect at December 31, 2014. The amounts listed below are in millions of U.S. dollars, except as otherwise stated.

| | Maturity Date | Range of Interest Rates | Total Remaining Principal Repayments | 2015 | 2016 | 2017 | 2018 | 2019 | Thereafter |
|---|---|---|---|---|---|---|---|---|---|
| **Consolidated Projects:** | | | | | | | | | |
| Epsilon Power Partners | January 2019 | 3.4% | $ 25.5 | $ 6.0 | $ 6.0 | $ 6.3 | $ 6.5 | $ 0.7 | $ |
| Piedmont | August 2018 | 5.2% | 64.0 | 4.5 | 3.3 | 4.7 | 51.5 | | |
| Cadillac | August 2025 | 6.0%-8.0% | 33.4 | 3.9 | 2.5 | 3.0 | 3.0 | 3.1 | 17.9 |
| Meadow Creek | December 2024 | 2.9%-5.6% | 164.9 | 4.6 | 5.3 | 5.3 | 6.0 | 6.7 | 137.0 |
| Rockland(1) | June 2027 | 6.4%-6.9% | 83.8 | 1.8 | 1.9 | 2.2 | 2.5 | 2.9 | 72.5 |
| Total Consolidated Projects | | | 371.6 | 20.8 | 19.0 | 21.5 | 69.5 | 13.4 | 227.4 |
| **Equity Method Projects:** | | | | | | | | | |
| Chambers(2) | December 2019 and 2023 | 4.5%-5.0% | 43.1 | 0.2 | 0.1 | | | 5.2 | 37.6 |
| Goshen | December 2022 | 2.9%-7.1% | 23.9 | 0.5 | 0.7 | 0.9 | 1.0 | 1.1 | 19.7 |
| Idaho Wind | December 2027 | 5.8% | 44.3 | 2.6 | 2.5 | 2.7 | 2.9 | 3.1 | 30.5 |
| Total Equity Method Projects | | | 111.3 | 3.3 | 3.3 | 3.6 | 3.9 | 9.4 | 87.8 |
| Total Project-Level Debt | | | $ 482.9 | $ 24.1 | $ 22.3 | $ 25.1 | $ 73.4 | $ 22.8 | $ 315.2 |

(1) We own a 50% interest in the Rockland project. We consolidate Rockland because as the managing member of the project, we have the control to direct most significant decisions in the day to day operations of the project. The maturities above represent 100% of the future principal payments on the Rockland debt.

(2) In June 2014, Chambers refinanced its project debt and issued (i) Series A (tax exempt) Bonds due December 2023, of which our proportionate share is $41.3 million and (ii) Series B (taxable) Bonds due December 2019, of which our proportionate share is $1.6 million. The above table does not include our $4.2 million proportionate share of issuance premiums.

***Preferred shares issued by a subsidiary company***

In 2007, a subsidiary acquired in our acquisition of the Partnership issued 5.0 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Shares") priced at Cdn$25.00 per share. Cumulative dividends are payable on a quarterly basis at the annual rate of Cdn$1.2125 per share. Beginning on June 30, 2012, the Series 1 Shares were redeemable by the subsidiary company at Cdn$26.00 per share, declining by Cdn$0.25 each year to Cdn$25.00 per share on or after June 30, 2016, plus, in each case, an amount equal to all accrued and unpaid dividends thereon.

In 2009, a subsidiary company acquired in our acquisition of the Partnership issued 4.0 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the "Series 2 Shares") priced at Cdn$25.00 per share. The Series 2 Shares pay fixed cumulative dividends of Cdn$1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate reset on December 31, 2014 and will reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. On December 31, 2014 and on December 31 every five years thereafter, the Series 2 Shares were and will be redeemable by the subsidiary company at Cdn$25.00 per share, plus an amount equal to all declared and unpaid dividends thereon to, but excluding the date fixed for redemption. The holders of the Series 2 Shares had and will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the "Series 3 Shares") of the subsidiary, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the subsidiary, at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate and 4.18%. On December 31, 2014 1,661,906 of Series 2 shares were converted to Series 3 shares.

The Series 1 Shares, the Series 2 Shares and the Series 3 Shares are fully and unconditionally guaranteed by us and by the Partnership on a subordinated basis as to: (i) the payment of dividends, as and when declared; (ii) the payment of amounts due on a redemption for cash; and (iii) the payment of amounts due on the liquidation, dissolution or winding up of the subsidiary company. If, and for so long as, the declaration or payment of dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares is in arrears, the Partnership will not make any distributions on its limited partnership units and we will not pay any dividends on our common shares.

The subsidiary company paid aggregate dividends of $11.6 million and $12.6 million on the Series 1 Shares and the Series 2 Shares for the years ended December 31, 2014 and 2013, respectively.

***Capital and Major Maintenance Expenditures***

Capital expenditures and major maintenance expenses for the projects are generally paid at the project level using project cash flows and project reserves. Therefore, the distributions that we receive from the projects are made net of capital expenditures needed at the projects. The operating projects which we own consist of large capital assets that have established commercial operations. On-going 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.

We expect to reinvest approximately $35.0 million in 2015 in our portfolio in the form of project capital expenditures and major maintenance expenses. As explained above, these investments are generally paid at the project level. We believe one of the benefits of our diverse fleet is that plant overhauls and other major expenditures do not occur in the same year for each facility. Recognized industry guidelines and original equipment manufacturer recommendations provide a source of data to

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assess major maintenance needs. In addition, we utilize predictive and risk-based analysis to refine our expectations, prioritize our spending and balance the funding requirements necessary for these expenditures over time. Future capital expenditures and major maintenance expenses may exceed the projected 2015 level as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

We invested approximately $33.2 million of project capital expenditures and major maintenance expenses for the year ended December 31, 2014. In all cases, scheduled maintenance outages during the year ended December 31, 2014 occurred at such times that did not adversely impact the facilities' availability requirements under their respective PPAs.

***Restricted Cash***

At December 31, 2014, restricted cash totaled $41.6 million as compared to $114.2 million as of December 31, 2013, of which $75.0 million was pledged to the lenders as security for the Prior Credit Facility. This $75 million was released from restricted cash to cash and cash equivalents in February 2014 as a result of the Senior Secured Credit Facilities, which, unlike the Prior Credit Facility, does not require us to maintain a $75 million restricted cash reserve. Projects with project-level debt generally have reserve requirements to support payments for major maintenance costs and project-level debt service. For projects that are consolidated, our share of these amounts is reflected as restricted cash on the consolidated balance sheet.

***Shelf Registrations***

On August 8, 2012, we filed with the SEC an automatic shelf registration statement (Registration No. 333-183135) for the potential offering and sale of debt and equity securities, including common shares issued under our dividend reinvestment program. At that time, because we were a well-known seasoned issuer, as defined in Rule 405 under the Securities Act, the registration statement was effective immediately upon filing. As a result of the decrease in our market capitalization, we can no longer offer and sell securities under that shelf registration. However, in February 2014, we filed a new registration statement, which became effective immediately upon filing, for the continued and uninterrupted issuance of common shares under our dividend reinvestment program.

**Contractual Obligations and Commercial Commitments**

The following table summarizes our contractual obligations as of December 31, 2014:

| | Payment Due by Period | | | | |
|---|---|---|---|---|---|
| | Less than 1 year | 1-3 Years | 4-5 Years | Thereafter | Total |
| Long-term debt including estimated interest[(1)(2)] | $ 130.7 | $ 862.6 | $ 282.1 | $ 1,237.5 | $ 2,512.9 |
| Operating leases | 1.4 | 3.9 | 1.2 | 4.5 | 11.0 |
| Operations and maintenance commitments | 7.9 | 22.2 | 6.4 | 30.2 | 66.7 |
| Fuel purchase and transportation obligations | 69.8 | 104.7 | 12.4 | 37.2 | 224.1 |
| Interconnection obligations | 5.1 | 15.4 | 5.1 | 19.4 | 45.0 |
| Other liabilities | 0.4 | | | 0.7 | 1.1 |
| Total contractual obligations | $ 215.3 | $ 1,008.8 | $ 307.2 | $ 1,329.5 | $ 2,860.8 |

(1) Debt represents our proportionate share of project long-term debt and corporate-level debt. Project debt is non-recourse to us and is generally amortized during the term of the respective revenue generating contracts of the projects. The range of interest rates on long-term consolidated project debt at December 31, 2014 was 2.9% to 9.0%.

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(2) Includes the mandatory amortization payments and an estimate of the 50% excess cash flow payments, as defined in the Credit Agreement, of the Senior Secured Credit Facilities.

**Guarantees**

We and our subsidiaries entered into various contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchases and sale agreements, joint venture agreements, operation and maintenance agreements, fuel purchase and transportation agreements and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for certain tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

In connection with the tax equity investments in our Canadian Hills project, we have expressly indemnified the tax investors for certain representations and warranties made by a wholly-owned subsidiary with respect to matters which we believe are remote, in our control and improbable to occur. The expiration dates of these guarantees vary from less than one year through the indefinite termination date of the project. Our maximum undiscounted potential exposure is limited to the amount of tax equity investment less cash distributions made to the investors and any amount equal to the net federal income tax benefits arising from production tax credits.

**Off-Balance Sheet Arrangements**

As of December 31, 2014, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

**Critical Accounting Policies and Estimates**

Accounting standards require information be included in financial statements about the risks and uncertainties inherent in significant estimates, and the application of GAAP involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining the useful lives and recoverability of property, plant and equipment and PPAs, the recoverability of equity investments, the recoverability of goodwill, the recoverability of deferred tax assets, the fair value of our derivatives instruments, the allocation of taxable income and losses, tax credits and cash distributions using Hypothetical Liquidation Book Value ("HLBV"), and fair values of acquired assets.

For a summary of our significant accounting policies, see Note 2 to the consolidated financial statements. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others; these policies are discussed below.

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*Impairment of long-lived assets and equity investments*

Long-lived assets, such as property, plant and equipment, and other intangible assets and liabilities subject to depreciation and amortization, are reviewed for impairment annually or 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 the asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of the asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds its fair value.

Investments in and the operating results of 50%-or-less owned entities not consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in such unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. We also review a project for impairment at the earlier of executing a new PPA (or other arrangement) or six months prior to the expiration of an existing PPA. Factors such as the business climate, including current energy and market conditions, environmental regulation, the condition of assets, and the ability to secure new PPAs are considered when evaluating long-lived assets for impairment. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment or, where applicable, estimated sales proceeds that are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long-term investments. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

*Goodwill*

Goodwill is not amortized. Instead, it is reviewed for impairment annually (in the fourth quarter) or more frequently if indicators of impairment exist. A significant amount of judgment is involved in determining if an indicator of impairment has occurred. Such indicators may include a prolonged decline in our market capitalization, deterioration in general economic conditions, adverse changes in the market in which a reporting unit operates, decreases in energy or capacity revenues as the result of re-contracting or increases in input costs that have a negative effect on earnings and cash flows, or a trend of negative or declining cash flows over multiple periods, among others. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of goodwill. Our goodwill is allocated among and evaluated for impairment at the reporting unit level, which is one level below our operating segments.

Effective January 1, 2012, we adopted a standard that provides an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of a reporting unit is less than its carrying amount. These factors include an assessment of macroeconomic and industry conditions, market events and circumstances as well as the overall financial performance of our reporting units. Because we have not been able to make a more likely than not determination for our reporting units, we have performed the two-step quantitative test for the years ended December 31, 2014 and 2013.

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Under the two-step quantitative impairment test, the evaluation of impairment involves comparing the current fair value of each reporting unit to its carrying value, including goodwill. In the event the estimated fair value of a reporting is less than the carrying value, additional analysis would be required. The additional analysis would compare the carrying amount of the reporting unit's goodwill with the implied fair value of that goodwill, which may involve the use of valuation experts. The implied fair value of goodwill is the excess of the fair value of the reporting unit over the fair value amounts assigned to all of the assets and liabilities of that unit as if the reporting unit was acquired in a business combination and the fair value of the reporting unit represented the purchase price. If the carrying value of goodwill exceeds its implied fair value, an impairment loss equal to such excess would be recognized, which could significantly and adversely impact reported results of operations and shareholders' equity.

We determine the fair value of our reporting units using an income approach with discounted cash flow ("DCF") models, as we believe forecasted cash flows are the best indicator of such fair value. A number of significant assumptions and estimates are involved in the application of the DCF model to forecast operating cash flows, including assumptions about discount rates, projected merchant power prices, generation, fuel costs and capital expenditure requirements. The undiscounted and discounted cash flows utilized in our step 1 and 2 goodwill impairment tests for our reporting units are generally based on approved reporting unit operating plans for years with contracted PPAs and historical relationships for estimates at the expiration of PPAs. All cash flow forecasts from DCF models utilize estimated plant output for determining assumptions around future generation and industry data forward power and fuel curves to estimate future power and fuel prices. We used historical experience to determine estimated future capital investment requirements. The discount rate applied to the DCF models represents the weighted average cost of capital ("WACC") consistent with the risk inherent in future cash flows of the particular reporting unit and is based upon an assumed capital structure, cost of long-term debt and cost of equity consistent with comparable independent power producers. The betas used in calculating the WACC rate were obtained from reputable third party sources. We utilized the assistance of valuation experts to perform step 1 and step 2 of the quantitative impairment test for several of our reporting units. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of goodwill.

The valuation of long lived assets and goodwill for the impairment analyses is considered a level 3 fair value measurement, which means that the valuation of the assets and liabilities reflect management's own judgments regarding the assumptions market participants would use in determining the fair value of the assets and liabilities. Fair value determinations require considerable judgment and are sensitive to changes in these underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of a goodwill impairment test will prove to be accurate predictions of the future. Examples of events or circumstances that could reasonably be expected to negatively affect the underlying key assumptions and ultimately impact the estimated fair value of our reporting units may include macroeconomic factors that significantly differ from our assumptions in timing or degree, increased input costs such as higher fuel prices and maintenance costs, or lower power prices than incorporated in our long-term forecasts. See "Risk Factors Risks Related to Our Business and Our Projects Impairment of goodwill or long-lived assets could have a material adverse effect on our business, results of operations and financial condition".

Our goodwill balance was $197.2 million at December 31, 2014 and is allocated among nine of our reporting units, of which six are included in the East segment ($84.7 million at December 31, 2014) and three are included in the West segment ($112.5 million at December 31, 2014).

During the second quarter of 2014, based on the continued deficit of our market capitalization as compared to our book carrying value, we determined that it was appropriate to initiate an event-driven test of the remaining goodwill at our reporting units. The test was performed as of August 31, 2014 during the third quarter of 2014.

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As a result of the event-driven goodwill assessment, we recorded a $17.9 million full impairment at the Kenilworth reporting unit (East segment), a $50.2 million full impairment at the Manchief reporting unit (West Segment) and a $23.7 million partial impairment at the Williams Lake reporting unit (West segment). The total impairment recorded in the three months ended September 30, 2014 was $91.8 million. The goodwill impairment recorded at each reporting unit was primarily due to (i) decreases in forward merchant energy prices subsequent to the expiration of the reporting units' respective energy service agreement ("ESA") or PPA, as applicable as compared to the assumptions at the time of the reporting units' acquisition in November 2011, (ii) the continued amortization of cash flows under the reporting units' respective ESA or PPAs and (iii) an increase in the discount rate reflecting increased re-contracting risk. At the time of its acquisition in November 2011, the fair value of the assets acquired and liabilities assumed for each of the Kenilworth, Manchief and Williams Lake reporting units were valued assuming a merchant basis for the period subsequent to the expiration of the projects' original ESAs or PPAs. As discussed above, these forecasted energy revenues on a merchant basis were higher than the energy prices currently forecasted to be in effect subsequent to the expiration of these reporting units' ESAs or PPAs. Power prices have declined from 2011 due to several factors including decreased demand and lower natural gas prices resulting from an abundance of shale gas. Our forecasts for discounted cash flows also reflect a higher level of uncertainty for re-contracting at prices that were previously forecasted in 2011.

In the fourth quarter of 2014, we performed our annual goodwill impairment test as of November 30, 2014. Of the nine remaining reporting units with goodwill recorded, only Williams Lake failed step 1 of the two-step test. However, no impairment was recorded because the implied value of its goodwill exceeded the carrying value of its goodwill. Under step 1 of our goodwill impairment tests, the total fair value of the Curtis Palmer, Morris, Mamquam, Nipigon, North Bay, Kapuskasing, Calstock and Moresby Lake reporting units exceeded their carrying value by approximately $138 million or 25%.

Under our accounting policies for long-lived assets and goodwill impairment, we also perform an impairment analysis at the earlier of (i) executing a new PPA (or other arrangement) and (ii) six months prior to the expiration of an existing PPA. The Tunis project's PPA expires on December 31, 2014 and accordingly, we performed a long-lived asset impairment test and a goodwill impairment test as of June 30, 2014. Based on the results of our long-lived asset impairment test, it was determined that the weighted average estimated undiscounted cash flows for Tunis over its remaining useful life did not exceed the carrying value of the property, plant and equipment at the Tunis reporting unit. As a result, the project recorded a $9.6 million long-lived asset impairment charge in the three months ended June 30, 2014 which was the difference between the carrying value of the project's property, plant and equipment and its estimated fair market value.

Subsequent to adjusting the carrying value of the Tunis reporting unit for the $9.6 million long-lived asset impairment, we performed an impairment analysis for the project's goodwill. The project failed step 1 of the impairment test because the weighted average estimated discounted cash flows over its remaining useful life did not exceed the carrying value of the Tunis reporting unit. We performed step 2 of the goodwill impairment test and wrote off all of the project's goodwill because the carrying value of goodwill exceeded its implied fair value. As a result, Tunis, a component of the East segment, recorded a $5.2 million goodwill impairment charge in the three months ended June 30, 2014. The implied fair value of goodwill was 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 were the purchase price. The total $14.8 million long-lived asset and goodwill impairment was primarily due to our assessment of the forecasted cash flows from re-contracting and other strategic outcomes.

We updated our probability-based long-lived asset impairment analysis for Tunis as of September 30, 2014 and December 31, 2014 and determined that, based on the weighted average

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estimated undiscounted cash flows for the project over its remaining useful life, no further impairment of long-lived assets was required.

*Fair value of derivatives*

We utilize derivative contracts to mitigate our exposure to fluctuations in fuel commodity prices and foreign currency rates and to balance our exposure to variable interest rates. We believe that these derivatives are generally effective in realizing these objectives. We also enter into long term fuel purchase agreements accounted for as derivatives that do not meet the scope exclusion for normal purchase or normal sales.

In determining fair value for our derivative assets and liabilities, we generally use the market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about market risk and/or the risks inherent in the inputs to the valuation techniques.

A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. Our derivative instruments are classified as Level 2. The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified with market data and valuation techniques do not involve significant judgment. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk-free interest rate. We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties.

Certain derivative instruments qualify for a scope exception to fair value accounting, as they are considered normal purchases or normal sales. The availability of this exception is based upon the assumption that we have the ability and it is probable to deliver or take delivery of the underlying physical commodity. Derivatives that are considered to be normal purchases and normal sales are exempt from derivative accounting treatment and are recorded as executory contracts.

*Income taxes and valuation allowance for deferred tax assets*

In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies. The valuation allowance is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards. As of December 31, 2014, we have recorded a valuation allowance of $168.6 million.

*Allocation of net income or losses to investors in certain variable interest entities*

For consolidated investments that allocate taxable income and losses, tax credits and cash distributions under complex allocation provisions of agreements with third-party investors, net income or loss is allocated to third-party investors for accounting purposes using HLBV. HLBV is a balance sheet oriented approach that calculates the change in the claims of each partner on the net assets of the investment at the beginning and end of each period. Each partner's claim is equal to the amount each party would receive or pay if the net assets of the investment were to liquidate at book value and the resulting cash was then distributed to investors in accordance with their respective liquidation preferences. We report the net income or loss attributable to the third-party investors as income (loss) attributable to noncontrolling interests in the consolidated statements of operations.

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*Acquired assets*

When we acquire a business, a portion of the purchase price is typically allocated to identifiable assets, such as property, plant and equipment, PPAs or fuel supply agreements. Fair value of these assets is determined primarily using the income approach, which requires us to project future cash flows and apply an appropriate discount rate. We amortize tangible and intangible assets with finite lives over their expected useful lives. Our estimates are based upon assumptions believed to be reasonable, but which are inherently uncertain and unpredictable. Assumptions may be incomplete or inaccurate, and unanticipated events and circumstances may occur. Incorrect estimates and assumptions could result in future impairment charges, and those charges could be material to our results of operations.

**Recent Accounting Developments**

*Adopted*

In July 2013, the FASB issued changes to the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. These changes require an entity to present an unrecognized tax benefit as a liability in the financial statements if (i) a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or (ii) the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset to settle any additional income taxes that would result from the disallowance of a tax position. Otherwise, an unrecognized tax benefit is required to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. Previously, there was diversity in practice as no explicit guidance existed. These changes became effective for us on January 1, 2014 and did not have a material impact on the consolidated financial statements.

In March 2013, the FASB issued changes to a parent entity's accounting for the cumulative translation adjustment upon derecognition of certain subsidiaries or groups of assets within a foreign entity or of an investment in a foreign entity. A parent entity is required to release any related cumulative foreign currency translation adjustment from accumulated other comprehensive income (loss) into net income (loss) in the following circumstances: (i) a parent entity ceases to have a controlling financial interest in a subsidiary or group of assets that is a business within a foreign entity if the sale or transfer results in the complete or substantially complete liquidation of the foreign entity in which the subsidiary or group of assets had resided; (ii) a partial sale of an equity method investment that is a foreign entity; (iii) a partial sale of an equity method investment that is not a foreign entity whereby the partial sale represents a complete or substantially complete liquidation of the foreign entity that held the equity method investment; and (iv) the sale of an investment in a foreign entity. These changes became effective for us on January 1, 2014 and had no impact on the consolidated financial statements.

In February 2013, the FASB issued changes to the accounting for obligations resulting from joint and several liability arrangements. These changes require an entity to measure such obligations for which the total amount of the obligation is fixed at the reporting date as the sum of (i) the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors, and (ii) any additional amount the reporting entity expects to pay on behalf of its co-obligors. An entity will also be required to disclose the nature and amount of the obligation as well as other information about those obligations. Examples of obligations subject to these requirements are debt arrangements and settled litigation and judicial rulings. These changes became effective for us on January 1, 2014 and had no impact on the consolidated financial statements.

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On January 1, 2013, we adopted changes issued by the FASB to the reporting of amounts reclassified out of accumulated other comprehensive income. These changes require an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required to be reclassified in its entirety to net income. For other amounts that are not required to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures that provide additional detail about those amounts. These requirements are to be applied to each component of accumulated other comprehensive income. Other than the additional disclosure requirements, the adoption of these changes had no impact on the consolidated financial statements.

On January 1, 2013, we adopted changes issued by the FASB to the testing of indefinite-lived intangible assets for impairment, similar to the goodwill changes issued in September 2011. These changes provide an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of an indefinite-lived intangible asset is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions; industry and market considerations; cost factors; overall financial performance; and other relevant entity-specific events. If an entity elects to perform a qualitative assessment and determines that an impairment is more likely than not, the entity is then required to perform the existing two-step quantitative impairment test, otherwise no further analysis is required. An entity also may elect not to perform the qualitative assessment and, instead, proceed directly to the two-step quantitative impairment test. The adoption of these changes had no impact on the consolidated financial statements.

In July 2012, the Financial Accounting Standards Board ("FASB") issued changes to the testing of indefinite-lived intangible assets for impairment, similar to the goodwill changes issued in September 2011. These changes provide an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of an indefinite-lived intangible asset is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions; industry and market considerations; cost factors; overall financial performance; and other relevant entity-specific events. If an entity elects to perform a qualitative assessment and determines that an impairment is more likely than not, the entity is then required to perform the existing two-step quantitative impairment test, otherwise no further analysis is required. An entity also may elect not to perform the qualitative assessment and, instead, proceed directly to the two-step quantitative impairment test. These changes became effective for us for any indefinite-lived intangible asset impairment test performed on January 1, 2013 or later. The adoption of these changes did not impact the consolidated financial statements.

In December 2011, the FASB issued changes to the disclosure of offsetting assets and liabilities. These changes require an entity to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The enhanced disclosures will enable users of an entity's financial statements to understand and evaluate the effect or potential effect of master netting arrangements on an entity's financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. These changes became effective for us on January 1, 2013. Other than the additional disclosure requirements, the adoption of these changes did not impact the consolidated financial statements.

On January 1, 2012, we adopted changes issued by the FASB to conform existing guidance regarding fair value measurement and disclosure between GAAP and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and amend certain principles or requirements for measuring

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fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio; application of premiums and discounts in a fair value measurement; and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. The adoption of these changes had no impact on our consolidated financial statements.

On January 1, 2012, we adopted changes issued by the FASB to the presentation of comprehensive income (loss). These changes give an entity the option to present the total of comprehensive income (loss), the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income (loss) or in two separate but consecutive statements; the option to present components of other comprehensive income (loss) as part of the statement of changes in shareholders' equity was eliminated. The items that must be reported in other comprehensive income (loss) or when an item of other comprehensive income (loss) must be reclassified to net income were not changed. Additionally, no changes were made to the calculation and presentation of earnings per share. We elected to present the two-statement option. Other than the change in presentation, the adoption of these changes had no impact on our consolidated financial statements.

*Issued*

In August 2014, the FASB issued changes to the disclosure of uncertainties about an entity's ability to continue as a going concern. Under GAAP, continuation of a reporting entity as a going concern is presumed as the basis for preparing financial statements unless and until the entity's liquidation becomes imminent. Even if an entity's liquidation is not imminent, there may be conditions or events that raise substantial doubt about the entity's ability to continue as a going concern. Because there is no guidance in GAAP about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern or to provide related note disclosures, there is diversity in practice whether, when, and how an entity discloses the relevant conditions and events in its financial statements. As a result, these changes require an entity's management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that financial statements are issued. Substantial doubt is defined as an indication that it is probable that an entity will be unable to meet its obligations as they become due within one year after the date that financial statements are issued. If management has concluded that substantial doubt exists, then the following disclosures should be made in the financial statements: (i) principal conditions or events that raised the substantial doubt, (ii) management's evaluation of the significance of those conditions or events in relation to the entity's ability to meet its obligations, (iii) management's plans that alleviated the initial substantial doubt or, if substantial doubt was not alleviated, management's plans that are intended to at least mitigate the conditions or events that raise substantial doubt, and (iv) if the latter in (iii) is disclosed, an explicit statement that there is substantial doubt about the entity's ability to continue as a going concern. These changes become effective for us for financial statements filed after December 15, 2016. We are currently evaluating the potential impact of these changes on the consolidated financial statements. Subsequent to adoption, this guidance will need to be applied by management at the end of each annual period and interim period therein to determine what, if any, impact there will be on the consolidated financial statements in a given reporting period.

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In April 2014, the FASB issued changes to reporting discontinued operations and disclosures of disposals of components of an entity. These changes require a disposal of a component to meet a higher threshold in order to be reported as a discontinued operation in an entity's financial statements. The threshold is defined as a strategic shift that has, or will have, a major effect on an entity's operations and financial results such as a disposal of a major geographical area or a major line of business. Additionally, the following two criteria have been removed from consideration of whether a component meets the requirements for discontinued operations presentation: (i) the operations and cash flows of a disposal component have been or will be eliminated from the ongoing operations of an entity as a result of the disposal transaction, and (ii) an entity will not have any significant continuing involvement in the operations of the disposal component after the disposal transaction. Furthermore, equity method investments now may qualify for discontinued operations presentation. These changes also require expanded disclosures for all disposals of components of an entity, whether or not the threshold for reporting as a discontinued operation is met, related to profit or loss information and/or asset and liability information of the component. These changes become effective on January 1, 2015. The adoption of these changes will not have an immediate impact on the consolidated financial statements. This guidance will need to be considered in the event that we initiate a disposal transaction.

In May 2014, the FASB issued changes to the recognition of revenue from contracts with customers. These changes created a comprehensive framework for all entities in all industries to apply in the determination of when to recognize revenue, and, therefore, supersede virtually all existing revenue recognition requirements and guidance. This framework is expected to result in less complex guidance in application while providing a consistent and comparable methodology for revenue recognition. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this principle, an entity should apply the following steps: (i) identify the contract(s) with a customer, (ii) identify the performance obligations in the contract(s), (iii) determine the transaction price, (iv) allocate the transaction price to the performance obligations in the contract(s), and (v) recognize revenue when, or as, the entity satisfies a performance obligation. These changes become effective on January 1, 2017. We are currently evaluating the potential impact of these changes on the consolidated financial statements.

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## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the risk that changes in market prices, such as foreign exchange rates, interest rates and commodity prices, will affect our cash flows or the value of our holdings of financial instruments. The objective of market risk management is to minimize the impact that market risks have on our cash flows as described in the following paragraphs.

Our market risk-sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in fuel and electricity commodity prices, currency exchange rates or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in fuel commodity prices, currency exchange rates or interest rates and the timing of transactions. See Note 14, *Accounting for derivative instruments and hedging activities* for additional information.

**Fuel Commodity Market Risk**

Our current and future cash flows are impacted by changes in electricity, natural gas, biomass and coal prices. See "Item 1A. Risk Factors Risks Related to Our Business and Our Projects Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects." We often employ (i) tolling structures, whereby an offtaker is responsible for fuel procurement, (ii) long-term fuel contracts, where we lock in a set quantity of fuel at a predetermined price or (iii) pass-through arrangements, whereby the cost of fuel is borne by the ultimate offtaker. The combination of long-term energy sales and fuel purchase agreements is generally designed to mitigate the impacts to cash flows of changes in commodity prices by passing through changes in fuel prices to the buyer of the energy.

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. We have entered into various natural gas swaps to effectively fix the price of 6.3 million Mmbtu of future natural gas purchases at Orlando, which is approximately 100% of our share of the expected on-peak natural gas purchases at the project through 2016 or approximately 63% of our share of the expected base load natural gas purchases for each of 2015 and 2016. Because projected on-peak gas exposure is fully hedged, a $1.00 MMBtu change in the price of natural gas would not impact estimated cash distributions for 2015.

In June 2014, the Partnership entered into contracts for the purchase of 2.9 million Gigajoules ("Gj") of future natural gas purchases beginning on November 1, 2014 and expiring on December 31, 2017 for our projects in Ontario. These contracts effectively fix the price of approximately 98% of our expected uncontracted gas requirements for each of 2014 and 2015 and 32% and 30% of our expected uncontracted gas requirements for 2016 and 2017, respectively. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2014. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

**Electricity Commodity Market Risk**

Our current and future cash flows are impacted by changes in electricity prices when our projects operate with no PPA or at projects that operate with PPAs that are based on spot market pricing. Our most significant exposure to market power prices is at the Chambers, Morris, and Selkirk projects. We are currently in negotiations with counterparties regarding the renewal or entry into new power purchase agreements. No assurance can be provided that we will be able to renew or enter into new power purchase agreements on favorable terms or at all. See Item 1A. "Risk Factors Risks Related to

Our Business and Our Projects The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition" and "Risk Factors Risks Related to Our Business and Our Projects Certain of our projects are exposed to fluctuations in the price of electricity, which may have a material adverse effect on the operating margin of these projects and on our business, results of operations and financial condition."

At our 40% owned Chambers project, our utility customer has the right to sell a portion of the plant's output into the spot power market if it is profitable to do so, and the Chambers project shares in the profits from these sales. In addition, during periods of low spot electricity prices the utility takes less generation, which negatively affects the project's operating margin. In 2015, projected cash distributions from Chambers would change by approximately $0.4 million per 10% change in the PJM-East spot price of electricity based on a forecasted around the clock ("ATC") price of $38.31 per MWh and certain other assumptions.

At Morris, where we own 100% of the project, the facility can sell approximately 120 MW above the off-taker's demand into the grid at market prices. If market prices do not justify the increased generation the project has no requirement to sell power in excess of the off-taker's demand which can negatively impact operating margins. In 2015, projected cash distributions from Morris would change by approximately $0.5 million per 10% change in the spot price of electricity based on the current level of approximately 175,000 MWh grid sales and all other variables being held constant.

At Selkirk, where we own 18.5% of the project, 100% of the project's capacity is currently not contracted and is sold into the spot power market or not sold at all if market prices do not support profitable operation of that portion of the facility. Forecasted distributions for 2015 would not change materially per 10% change in the forecasted spot price of electricity.

When a PPA expires or is terminated, it is possible that the price received by the project for power under subsequent arrangements may be reduced and in some cases, significantly. Our project may not be able to secure a new agreement and could be exposed to sell power at spot market price. See Item 1A. "Risk Factors Risk Related to Our Business and Our Projects The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition." It is possible that subsequent PPAs or the spot market 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.

**Foreign Currency Exchange Risk**

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as many of our projects generate cash flow in U.S. dollars and Canadian dollars but we pay dividends to shareholders, if and when declared by the board of directors, interest on corporate level long-term debt and all but one of our convertible debentures, predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on any future payments of dividends to shareholders. From time to time, we execute this strategy utilizing cash flows from our projects that generate Canadian dollars and by entering into forward contracts to purchase Canadian dollars. These foreign exchange forward contracts are recorded at estimated fair value based on quoted market prices and the estimation of the counter-party's credit risk. Changes in the fair value of the foreign currency forward contracts are recorded in foreign exchange (gain) loss in the consolidated statements of operations. As of December 31, 2014, we have no foreign currency forward contracts as there are sufficient Canadian dollars generated from the business to cover Canadian dollar obligations.

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The following table contains the components of recorded foreign exchange (gain) loss for the years ended December 31, 2014, 2013, and 2012:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Unrealized foreign exchange (gain) loss: | | | |
| Convertible debentures, MTN's, and other | $ (39.9) | $ (32.4) | $ 7.0 |
| Foreign currency forwards | 1.1 | 19.4 | 12.0 |
| | (38.8) | (13.0) | 19.0 |
| Realized foreign exchange loss (gains) on forward contract settlements | 0.5 | (14.4) | (18.5) |
| | $ (38.3) | $ (27.4) | $ 0.5 |

A 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar would have a $35.8 million impact on the carrying value of convertible debentures denominated in Canadian dollars at December 31, 2014.

**Interest Rate Risk**

Changes in interest rates impact cash payments that are required on our debt instruments as approximately 22% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at variable rates or is not financially hedged through the use of interest rate swaps. After considering the impact of interest rate swaps described below, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest at equity investments, by approximately $1.3 million at December 31, 2014. The Term Loan Facility has a LIBOR floor of 1.00%, and one month LIBOR at December 31, 2014 was approximately 0.17%. If LIBOR were greater than or equal to 1.00%, a change in interest of 100 basis points would change annual interest costs by $4.3 million.

*The Partnership*

On May 5, 2014 the Partnership entered into interest rate swap agreements to mitigate exposure to changes in the Adjusted Eurodollar Rate for $199.0 million notional amount ($182.7 million at December 31, 2014) of the $600 million aggregate principal amount of borrowings ($541.5 million at September 30, 2014) under the Term Loan Facility. Borrowings under the $600 million Term Loan Facility bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 3.75%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00% resulting in a minimum of a 4.75% all-in rate on the Term Loan Facility. As a result of entering into the swap agreements, the all-in rate for $199.0 million of the Term Loan Facility cannot be less than 4.91% if the Adjusted Eurodollar Rate is equal to or greater than 1.00%. If the Adjusted Eurodollar Rate is below 1.00%, we will pay interest at a rate equivalent to the minimum 4.75% all-in rate plus any difference between the actual three month Adjusted Eurodollar Rate and 1.16%. $182.7 million of notional amount remains on the interest rate swap agreements at December 31, 2014.

The interest rate swap agreements were effective June 30, 2014 and terminate on December 29, 2017. The interest rate swap agreements are not designated as hedges and changes in their fair market value will be recorded in the consolidated statements of operations.

*Epsilon Power Partners*

Epsilon Power Partners, a wholly owned subsidiary, is exposed to changes in interest rates related to its variable-rate non-recourse debt and previously had an interest rate swap to mitigate this exposure. The interest rate swap agreement effectively converted the floating rate debt to a fixed

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interest rate of 7.37% and had a maturity date of July 2019. The notional amount of the swap matched the outstanding principal balance over the remaining life of Epsilon Power Partners' debt. On February 20, 2014, we paid $2.6 million to terminate this contract in connection with the termination of our prior revolving credit facility. We recorded interest expense related to its settlement in the consolidated statement of operations for the year ended December 31, 2014.

*Cadillac*

We have an interest rate swap at our consolidated Cadillac project to economically fix its exposure to changes in interest rates related to the variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Cadillac debt and changes in its fair market value are recorded in other comprehensive income (loss). The interest rate swap expires on September 30, 2025.

In accounting for the cash flow hedge, gains and losses on the derivative contract are reported in other comprehensive income (loss), but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net income (loss). That is, for cash flow hedge, all effective components of the derivative contract's gains and losses are recorded in other comprehensive income (loss), pending occurrence of the expected transaction. Other comprehensive income (loss) consists of those financial items that are included in "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets but not included in our net income (loss). Thus, in highly effective cash flow hedges, where there is no ineffectiveness, other comprehensive income (loss) changes by exactly as much as the derivative contracts and there is no impact on net income (loss) until the expected transaction occurs.

*Piedmont*

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converts the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.8% through February 29, 2016. From February 2016 until the maturity of the debt in November 2017, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.5%. The swap continues at the fixed rate of 4.47% from the maturity of the debt in November 2017 until November 2030. Prior to conversion of the Piedmont Construction loan facility to a term loan, the notional amounts of the interest rate swap agreements matched the estimated outstanding principal balance of Piedmont's construction loan facility. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively. As a result of the Piedmont term loan conversion on February 14, 2014, these swap agreements were amended to reduce the notional amounts to match the outstanding $68.5 million principal of the term loan. We recorded $1.0 million of deferred financing costs related to this transaction in the consolidated balance sheets at December 31, 2014. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

*Meadow Creek*

The Meadow Creek project has interest rate swap agreements to economically fix the exposure to changes in interest rates related to 75% of the outstanding variable-rate non-recourse debt at the project. These swaps effectively modify the project's exposure by converting the project's floating rate debt to a fixed basis. The interest rate swaps are with various counterparties and swap the expected interest payments from floating LIBOR to fixed rates structured in two tranches. The first tranche is for the notional amount due on the term loan through December 31, 2024 and fixes the interest rate at

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2.3% plus an applicable margin of 2.9%-3.3%. The second tranche is the post-term portion of the loan, or the balloon payment and commences on December 31, 2024 and ends on December 31, 2030 fixing the interest rate at 7.2%.

*Rockland*

The Rockland project entered into interest rate swaps to manage interest rate risk exposure. These swaps effectively modify the project's exposure by converting the project's floating rate debt to a fixed basis. The interest rate swaps are with various counterparties and swap 100% of the expected interest payments from floating LIBOR to fixed rates structured in two tranches. The first tranche is for the expected interest payments through December 31, 2026 and fixes the interest rate at 4.2% plus an applicable margin of 2.2%-2.7%. The second tranche is for the expected interest payments for the period beginning December 31, 2026 and ending December 31, 2031, fixing the interest rate at 7.8%.

**ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**

Our consolidated financial statements are appended to the end of this Annual Report on Form 10-K, beginning on page F-1.

**ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE**

None.

**ITEM 9A. CONTROLS AND PROCEDURES**

(a) Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have evaluated the company's disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act, as of the end of the period covered by this report, and they have concluded that these controls and procedures are effective.

(b) Management's Report on Financial Statements and Practices

The accompanying Consolidated Financial Statements of Atlantic Power Corporation were prepared by management, which is responsible for their integrity and objectivity. The statements were prepared in accordance with generally accepted accounting principles and include amounts that are based on management's best judgments and estimates. The other financial information included in this annual report is consistent with that in the financial statements.

Management also recognizes its responsibility for conducting the Company's affairs according to the highest standards of personal and corporate conduct. This responsibility is characterized and reflected in key policy statements issued from time to time regarding, among other things, conduct of its business activities within the laws of the host countries in which the Company operates and potentially conflicting outside business interests of its employees. The Company maintains a systematic program to assess compliance with these policies.

(c) Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-14(f) under the Exchange Act. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2014 using the criteria established in *Internal Control Integrated*

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*Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on our evaluation under the COSO framework, management has concluded that our internal control over financial reporting is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of their inherent limitations, our disclosure controls and procedures and our internal control over financial reporting may not prevent errors or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to risks, including that the controls may become inadequate because of changes in conditions or that the degree of compliance with our policies or procedures may deteriorate.

(d) Attestation Report of the Registered Public Accounting Firm

The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 15 of this annual report Form 10-K on page F-2.

(e) Changes in Internal Control over Financial Reporting

There have been no changes in internal controls over financial reporting during the fourth quarter of 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

**ITEM 9B. OTHER INFORMATION**

None.

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## PART III

### ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information concerning our directors and executive officers required by Item 10 will be included in the Proxy Statement and is incorporated herein by reference.

We have adopted a code of ethics that applies to directors, managers, officers and employees. This code of ethics, titled "Code of Business Conduct and Ethics," is posted on our website. The internet address for our website is *www.atlanticpower.com*, and the "Code of Business Conduct and Ethics" may be found from our main Web page by clicking first on "About Us" and then on "Code of Conduct."

We intend to satisfy any disclosure requirement under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the "Code of Business Conduct and Ethics" by posting such information on our website, on the Web page found by clicking through to "Conduct of Conduct" as specified above.

### ITEM 11. EXECUTIVE COMPENSATION

The information concerning our directors and executive officers required by Item 11 will be included in the Proxy Statement and is incorporated herein by reference.

### ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information concerning security ownership and other matters required by Item 12 will be included in the Proxy Statement and is incorporated herein by reference.

### ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information concerning certain relationships and related transactions required by Item 13 will be included in the Proxy Statement and is incorporated herein by reference.

### ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information concerning principal accountant fees and services required by Item 14 will be included in the Proxy Statement and is incorporated herein by reference.

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## PART IV

### ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

See "Index to Consolidated Financial Statements" on page F-1 of this Annual Report on Form 10-K.

(a)(2) Financial Statement Schedules

See "Index to Consolidated Financial Statements" on page F-1 of this Annual Report on Form 10-K. Schedules other than that listed have been omitted because of the absence of the conditions under which they are required or because the information required is shown in the consolidated financial statements or the notes thereto.

(a)(3) Exhibits

### EXHIBIT INDEX

| Exhibit No. | Description |
|---|---|
| 2.1 | Plan of Arrangement of Atlantic Power Corporation, dated as of November 24, 2005 (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 2.2 | Arrangement Agreement, dated as of June 20, 2011, among Capital Power Income L.P., CPI Income Services Ltd., CPI Investments Inc. and Atlantic Power Corporation (incorporated by reference to our Current Report on Form 8-K filed on June 24, 2011) |
| 3.1 | Articles of Continuance of Atlantic Power Corporation, dated as of June 29, 2010 (incorporated by reference to our registration statement on Form 10-12B filed on July 9, 2010) |
| 4.1 | Form of common share certificate (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.2 | Trust Indenture, dated as of October 11, 2006 between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.3 | First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Secured Debentures, dated November 27, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.4 | Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 17, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.5 | Form of First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form S-1/A (File No. 33-138856) filed on September 27, 2010) |

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| Exhibit No. | Description |
| --- | --- |
| 4.6 | Second Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated July 5, 2012, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our Current Report on Form 8-K filed on July 6, 2012) |
| 4.7 | Third Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated August 17, 2012, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our Current Report on Form 8-K filed on August 20, 2012) |
| 4.8 | Fourth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of November 29, 2012, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A. (incorporated by reference to our Current Report on Form 8-K filed on November 30, 2012) |
| 4.9 | Fifth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 11, 2012, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A. (incorporated by reference to our Current Report on Form 8-K filed on December 11, 2012) |
| 4.10 | Sixth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of March 22, 2013, among Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our Current Report on Form 8-K filed on March 26, 2013) |
| 4.11 | Indenture, dated as of November 4, 2011, by and among Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Current Report on Form 8-K filed on November 7, 2011) |
| 4.12 | First Supplemental Indenture, dated as of November 5, 2011, by and among the New Guarantors signatory thereto, Atlantic Power Corporation, the Existing Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Current Report on Form 8-K filed on November 7, 2011) |
| 4.13 | Second Supplemental Indenture, dated as of November 5, 2011, by and among Curtis Palmer LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Current Report on Form 8-K filed on November 7, 2011) |
| 4.14 | Third Supplemental Indenture, dated as of February 22, 2012, by and among Atlantic Oklahoma Wind, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Annual Report on Form 10-K filed on March 1, 2013) |
| 4.15 | Fourth Supplemental Indenture, dated as of August 3, 2012, by and among Atlantic Rockland Holdings, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Annual Report on Form 10-K filed on March 1, 2013) |

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| Exhibit No. | Description |
|---|---|
| 4.16 | Fifth Supplemental Indenture, dated as of November 29, 2012, by and among Atlantic Ridgeline Holdings, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Annual Report on Form 10-K filed on March 1, 2013) |
| 4.17 | Sixth Supplemental Indenture, dated as of January 29, 2013, by and among the New Guarantors named therein, Atlantic Power Corporation, the Existing Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Annual Report on Form 10-K filed on March 1, 2013) |
| 4.18 | Registration Rights Agreement, dated as of November 4, 2011, by and among, Atlantic Power Corporation, the Guarantors listed on Schedule A thereto and Morgan Stanley & Co. LLC and TD Securities (USA) LLC, as representatives of the several Initial Purchasers (incorporated by reference to our Current Report on Form 8-K filed on November 7, 2011) |
| 4.19 | Shareholder Rights Plan Agreement, dated effective as of February 28, 2013, between Atlantic Power Corporation and Computershare Investor Services, Inc., which includes the Form of Right Certificate as Exhibit A (incorporated by reference to our Current Report on Form 8-K filed on February 28, 2013) |
| 4.20 | Advance Notice Policy, dated April 1, 2013 (incorporated by reference to our Current Report on Form 8-K filed on April 3, 2013) |
| 10.1 | Credit and Guaranty Agreement, dated as of February 24, 2014, among Atlantic Power Limited Partnership, as Borrower, Certain Subsidiaries of Atlantic Power Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of American, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Joint Lead Arrangers and Joint Bookrunners, Union Bank, N.A. and RBC Capital Markets, as Revolver Joint Lead Arrangers and Revolver Joint Bookrunners, Union Bank, N.A. and Royal Bank of Canada, as Revolver Co- Documentation Agents, and Goldman Sachs Lending Partners LLC, as Administrative Agent and Collateral Agent (incorporated by reference to our Annual Report on Form 10-K filed on February 28. 2014). |
| 10.2 | Second Amended and Restated Credit Agreement dated August 2, 2013, as amended, among Atlantic Power Corporation, Atlantic Power Generation, Inc. and Atlantic Power Transmission, Inc., the Lenders signatory thereto and Bank of Montreal, as Administrative Agent (incorporated by reference to our Current Report on Form 8-K filed on August 5, 2013) |
| 10.3 | Consent, dated as of November 19, 2012, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc. the Lenders signatory thereto and Bank of Montreal, as Administrative Agent (incorporated by reference to our Current Report on Form 8-K filed on November 21, 2012) |
| 10.4 | Consent and Release, dated as of January 15, 2013, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., the Subsidiaries signatory thereto, the Lenders signatory thereto and Bank of Montreal, as Administrative Agent and Collateral Agent (incorporated by reference to our Annual Report on From 10-K filed on March 1, 2013) |

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| Exhibit No. | Description |
|---|---|
| 10.5 | Modification and Joinder Agreement, dated as of January 15, 2013, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., Ridgeline Energy LLC, PAH RAH Holding Company LLC, Ridgeline Eastern Energy LLC, Ridgeline Energy Solar LLC, Lewis Ranch Wind Project LLC, Hurricane Wind LLC, Ridgeline Power Services LLC, Ridgeline Energy Holdings, Inc., Ridgeline Alternative Energy LLC, Frontier Solar LLC, PAH RAH Project Company LLC, Monticello Hills Wind LLC, Dry Lots Wind LLC, Smokey Avenue Wind LLC, Saunders Bros. Transportation Corporation, Bruce Hill Wind LLC, South Mountain Wind LLC, Great Basin Solar Ranch LLC, Goshen Wind Holdings LLC, Meadow Creek Holdings LLC, Ridgeline Holdings Junior Inc., Rockland Wind Ridgeline Holdings LLC, Meadow Creek Intermediate Holdings LLC and the other Subsidiaries party thereto in favor of Bank of Montreal, as Administrative Agent (incorporated by reference to our Quarterly Report on Form 10-K filed on March 1, 2013) |
| 10.6+ | Amended and Restated Employment Agreement, dated as of April 15, 2013 between Atlantic Power Corporation and Barry Welch (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.7+ | Amended and Restated Employment Agreement, dated as of April 15, 2013 between Atlantic Power Corporation and Paul Rapisarda (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.8+ | Employment Agreement, dated April 15, 2013, between Atlantic Power Corporation and Terrence Ronan (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.9+ | Employment Agreement, dated April 15, 2013, between Atlantic Power Corporation and Edward C. Hall (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.10+ | Addendum to Executive Employment Agreements of each of Terrence Ronan and Edward Hall, dated August 30, 2013 (incorporated by reference to our Current Report on Form 8-K filed on September 5, 2013) |
| 10.11+ | Deferred Share Unit Plan, dated as of April 24, 2007 of Atlantic Power Corporation (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 10.12+ | Third Amended and Restated Long-Term Incentive Plan (incorporated by reference to our registration statement on Form 10-12B filed on July 9, 2010) |
| 10.13+ | Fourth Amended and Restated Long-Term Incentive Plan (incorporated by reference to our Annual Report on Form 10-K filed on February 29, 2012) |
| 10.14+ | Fifth Amended and Restated Long-Term Incentive Plan (incorporated by reference to our Current Report on Form 8-K filed on April 11, 2013) |
| 10.15+ | Amendment No. 1 to the Fifth Amended and Restated Long-Term Incentive Plan of the Company (incorporated by reference to Exhibit A to Schedule B of the Company's definitive Proxy Statement on Schedule 14A filed on April 30, 2014) |
| 10.16+ | Participation Agreement and Confirmation between the Company and Paul H. Rapisarda, dated April 11, 2013 (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |

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| Exhibit No. | Description |
| --- | --- |
| 10.17+ | Participation Agreement and Confirmation (performance-based vesting) between the Company and Terrence Ronan, dated April 11, 2013 (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.18+ | Participation Agreement and Confirmation between the Company and Edward C. Hall, dated April 2, 2013 (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.19+ | Participation Agreement and Confirmation (time-vesting) between the Company and Terrence Ronan, dated April 11, 2013 (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.20+ | Offer Letter between the Company and Edward C. Hall, dated March 26, 2013 (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.21 | Amended and Restated Operating Agreement, dated as of March 30, 2012, between Atlantic Oklahoma Wind, LLC and Apex Wind Energy Holdings, LLC (incorporated by reference to our Quarterly Report on Form 10-Q filed November 4, 2011) |
| 10.22 | Termination of the Operating Agreement of Canadian Hills Wind, LLC, dated as of December 28, 2012 (incorporated by reference to our Current Report on Form 8-K filed on January 2, 2013) |
| 10.23 | Purchase and sale agreement, dated as of January 30, 2013 among Quantum Lake LP, LLC, Quantum Lake GP, LLC, Quantum Pasco LP, LLC, Quantum Pasco GP, LLC, Quantum Auburndale LP, LLC and Quantum Auburndale GP, LLC (as Buyers) and Lake Investment, LP, NCP Lake Power, LLC, Teton New Lake, LLC, NCP Dadee Power, LLC, Dade Investment, LP, Auburndale, LLC and Auburndale GP, LLC (as Sellers) (incorporated by reference to our Quarterly Report on Form 10-Q filed on May 8, 2013) |
| 10.25+ | Executive Severance and Release Agreement by and between Atlantic Holdings, the Company, and Barry E. Welch, dated September 22, 2014 (incorporated by reference to our Current Report on Form 8-K filed on September 23, 2014) |
| 10.26+ | Employment Agreement between the Company and Kenneth Hartwick, dated September 22, 2014 (incorporated by reference to our Current Report on Form 8-K/A filed on September 23, 2014) |
| 10.27+ | Executive Severance and Release Agreement by and between Atlantic Holdings, the Company and Paul H. Rapisarda, dated October 21, 2014 (incorporated by reference to our Current Report on Form 8-K filed on October 22, 2014) |
| 10.28 | Agreement dated November 24, 2014, by and among Clinton Group and the Company (incorporated by reference to our Current Report on Form 8-K filed on November 25, 2014) |
| 10.29+ | Employment Agreement among the Company, Atlantic Power Services, LLC and James J. Moore, Jr., dated January 22, 2015 (incorporated by reference to our Current Report on Form 8-K filed on January 23, 2015) |
| 10.30+ | Transition Equity Grant Participation Agreement between Atlantic Power Services, LLC and James J. Moore, Jr., dated January 22, 2015 (incorporated by reference to our Current Report on Form 8-K filed on January 23, 2015 |
| 10.31+ | Executive Severance and Release Agreement by and among Atlantic Power Holdings, Inc., the Company and Edward C. Hall, dated February 12, 2015 (incorporated by reference to our Current Report on Form 8-K filed on February 13, 2015) |

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| Exhibit No. | Description |
|---|---|
| 16.1 | Letter from KPMG LLP, Chartered Accountants, to the Securities and Exchange Commission, dated August 10, 2010 (incorporated by reference to our Current Report on Form 8-K filed on August 10, 2010) |
| 21.1* | Subsidiaries of Atlantic Power Corporation |
| 23.1* | Consent of KPMG LLP |
| 31.1* | Certification of Chief Executive Officer pursuant to Rule 13a- 14(a)/15d-14(a) under the Exchange Act |
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13a- 14(a)/15d-14(a) under the Exchange Act |
| 32.1** | Certification of the Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2** | Certification of the Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101* | The following materials from our Annual Report on Form 10-K for the year ended December 31, 2014 formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Shareholders' Equity, (iv) the Consolidated Statements of Cash Flows, and (v) related notes to these financial statements. |

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+ Indicates management contract or compensatory plan or arrangement.

* Filed herewith.

** Furnished herewith.

(b) Exhibits:

See Item 15(a)(3) above.

(c) Financial Statement Schedules:

See Item 15(a)(2) above.

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**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 26, 2015

Atlantic Power Corporation

By: /s/ TERRENCE RONAN

Name: Terrence Ronan
Title: *Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer)*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ JAMES M. MOORE<br>James M. Moore | President, Chief Executive Officer and Director (principal executive officer) | February 26, 2015 |
| /s/ TERRENCE RONAN<br>Terrence Ronan | Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer) | February 26, 2015 |
| /s/ IRVING R. GERSTEIN<br>Irving R. Gerstein | Chairman of the Board | February 26, 2015 |
| /s/ R. FOSTER DUNCAN<br>R. Foster Duncan | Director | February 26, 2015 |
| /s/ KENNETH M. HARTWICK<br>Kenneth M. Hartwick | Director | February 26, 2015 |
| /s/ KEVIN T. HOWELL<br>Kevin T. Howell | Director | February 26, 2015 |
| /s/ HOLLI LADHANI<br>Holli Ladhani | Director | February 26, 2015 |

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| Signature | Title | Date |
|---|---|---|
| /s/ JOHN A. MCNEIL<br>John A. McNeil | Director | February 26, 2015 |
| /s/ TERESA M. RESSEL<br>Teresa M. Ressel | Director | February 26, 2015 |

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**Atlantic Power Corporation**

**Index to Consolidated Financial Statements**

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**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Shareholders
Atlantic Power Corporation:

We have audited Atlantic Power Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control  Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Atlantic Power Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Atlantic Power Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control  Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Atlantic Power Corporation and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive loss, shareholders' equity, cash flows and related financial statement schedule for each of the years in the three-year period ended December 31, 2014, and our report dated February 26, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

New York, New York
February 26, 2015

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**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Shareholders
Atlantic Power Corporation:

We have audited the accompanying consolidated balance sheets of Atlantic Power Corporation and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive loss, shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2014. In connection with our audits of the consolidated financial statements, we also have audited financial statement schedule "Schedule II Valuation and Qualifying Accounts." These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlantic Power Corporation and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Atlantic Power Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 26, 2015 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

New York, New York
February 26, 2015

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**ATLANTIC POWER CORPORATION**

**CONSOLIDATED BALANCE SHEETS**

**(in millions of U.S. dollars)**

| | December 31, 2014 | December 31, 2013 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 109.9 | $ 158.6 |
| Restricted cash | 22.5 | 96.2 |
| Accounts receivable | 57.4 | 64.3 |
| Current portion of derivative instruments asset (Note 14) | | 0.2 |
| Inventory (Note 6) | 19.3 | 16.0 |
| Prepayments and other current assets | 16.3 | 16.1 |
| Refundable income taxes | 0.2 | 4.0 |
| Total current assets | 225.6 | 355.4 |
| Property, plant, and equipment, net (Note 7) | 1,673.4 | 1,813.4 |
| Equity investments in unconsolidated affiliates (Note 5) | 343.9 | 394.3 |
| Power purchase agreements and intangible assets, net (Note 9) | 381.4 | 451.5 |
| Goodwill (Note 8) | 197.2 | 296.3 |
| Derivative instruments asset (Notes 14) | 1.1 | 13.0 |
| Restricted cash | 19.1 | 18.0 |
| Deferred financing costs | 64.2 | 41.7 |
| Other assets | 10.7 | 11.4 |
| Total assets | $ 2,916.6 | $ 3,395.0 |
| **Liabilities** | | |
| Current liabilities: | | |
| Accounts payable | $ 11.0 | $ 14.0 |
| Accrued interest | 5.4 | 17.7 |
| Other accrued liabilities | 34.9 | 58.8 |
| Current portion of long-term debt (Note 11) | 26.4 | 216.2 |
| Current portion of convertible debentures (Note 12) | | 42.1 |
| Current portion of derivative instruments liability (Note 14) | 39.2 | 28.5 |
| Dividends payable | | 6.8 |
| Other current liabilities | 6.8 | 5.3 |
| Total current liabilities | 123.7 | 389.4 |
| Long-term debt (Note 11) | 1,388.3 | 1,254.8 |
| Convertible debentures (Note 12) | 340.6 | 363.1 |
| Derivative instruments liability (Note 14) | 57.5 | 76.1 |
| Deferred income taxes (Note 15) | 92.4 | 111.5 |
| Power purchase and fuel supply agreement liabilities, net (Note 9) | 33.4 | 38.7 |
| Other long-term liabilities (Note 10) | 64.2 | 65.4 |
| Commitments and contingencies (Note 23) | | |
| Total liabilities | 2,100.1 | 2,299.0 |
| **Equity** | | |

| | | |
|---|---|---|
| Common shares, no par value, unlimited authorized shares; 121,323,614 and 120,205,813 issued and outstanding at December 31, 2014 and December 31, 2013, respectively | 1,288.4 | 1,286.1 |
| Preferred shares issued by a subsidiary company (Note 19) | 221.3 | 221.3 |
| Accumulated other comprehensive loss (Note 4) | (68.3) | (22.4) |
| Retained deficit | (863.9) | (655.4) |
| Total Atlantic Power Corporation shareholders' equity | 577.5 | 829.6 |
| Noncontrolling interests | 239.0 | 266.4 |
| Total equity | 816.5 | 1,096.0 |
| Total liabilities and equity | $ 2,916.6 | $ 3,395.0 |

See accompanying notes to consolidated financial statements.

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**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF OPERATIONS**

**(in millions of U.S. dollars, except per share amounts)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2014** | **2013** | **2012** |
| Project revenue: | | | |
| Energy sales | $ 315.9 | $ 302.2 | $ 214.5 |
| Energy capacity revenue | 161.3 | 163.7 | 147.2 |
| Other | 92.0 | 78.2 | 68.1 |
| | 569.2 | 544.1 | 429.8 |
| Project expenses: | | | |
| Fuel | 210.4 | 194.3 | 164.9 |
| Operations and maintenance | 130.2 | 150.8 | 119.6 |
| Development | 3.7 | 7.2 | |
| Depreciation and amortization | 162.6 | 166.1 | 116.6 |
| | 506.9 | 518.4 | 401.1 |
| Project other income (expense): | | | |
| Change in fair value of derivative instruments (Notes 13 and 14) | (8.7) | 49.5 | (59.3) |
| Equity in earnings of unconsolidated affiliates (Note 5) | 25.8 | 26.9 | 15.2 |
| Gain on sale of equity investments | 8.6 | 30.4 | 0.6 |
| Interest expense, net | (31.9) | (34.4) | (16.4) |
| Impairment (Note 8) | (106.6) | (34.9) | |
| Other income, net | | 0.5 | |
| | (112.8) | 38.0 | (59.9) |
| Project (loss) income | (50.5) | 63.7 | (31.2) |
| Administrative and other expenses (income): | | | |
| Administration | 37.9 | 35.2 | 28.3 |
| Interest, net | 146.7 | 104.1 | 89.8 |
| Foreign exchange (gain) loss (Note 14) | (38.3) | (27.4) | 0.5 |
| Other income, net | (2.8) | (10.5) | (5.7) |
| | 143.5 | 101.4 | 112.9 |
| Loss from continuing operations before income taxes | (194.0) | (37.7) | (144.1) |
| Income tax benefit (Note 15) | (11.9) | (19.5) | (28.1) |
| Loss from continuing operations | (182.1) | (18.2) | (116.0) |
| Net (loss) income from discontinued operations, net of tax (Note 21) | (0.1) | (5.6) | 15.7 |
| Net loss | (182.2) | (23.8) | (100.3) |
| Net loss attributable to noncontrolling interests | (16.4) | (3.4) | (0.6) |
| Net income attributable to preferred shares dividends of a subsidiary company | 11.6 | 12.6 | 13.1 |
| Net loss attributable to Atlantic Power Corporation | $ (177.4) | $ (33.0) | $ (112.8) |

| | | | |
|---|---|---|---|
| Basic and diluted loss per share: (Note 20) | | | |
| Loss from continuing operations attributable to Atlantic Power Corporation | $ (1.47) | $ (0.23) | $ (1.10) |
| (Loss) income from discontinued operations, net of tax | | (0.05) | 0.13 |
| Net loss attributable to Atlantic Power Corporation | $ (1.47) | $ (0.28) | $ (0.97) |
| Weighted average number of common shares outstanding: (Note 20) | | | |
| Basic | 120.7 | 119.9 | 116.4 |
| Diluted | 120.7 | 119.9 | 116.4 |

See accompanying notes to consolidated financial statements.

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**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS**

**(in millions of U.S. dollars)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2014** | **2013** | **2012** |
| Net loss | $ (182.2) | $ (23.8) | $ (100.3) |
| Other comprehensive (loss) income, net of tax: | | | |
| Unrealized (loss) income on hedging activities | $ (1.0) | $ 0.7 | $ (0.9) |
| Net amount reclassified to earnings | 0.9 | 0.9 | 0.9 |
| Net unrealized (loss) gain on derivatives | (0.1) | 1.6 | |
| Defined benefit plan, net of tax | (1.7) | 1.4 | (1.3) |
| Foreign currency translation adjustments, net of tax | (44.1) | (34.8) | 15.9 |
| Other comprehensive (loss) income, net of tax | (45.9) | (31.8) | 14.6 |
| Comprehensive loss | (228.1) | (55.6) | (85.7) |
| Less: Comprehensive (loss) income attributable to noncontrolling interests | (4.8) | 9.2 | 12.5 |
| Comprehensive loss attributable to Atlantic Power Corporation | $ (223.3) | $ (64.8) | $ (98.2) |

See accompanying notes to consolidated financial statements.

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**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY**

**(in millions of U.S. dollars)**

| | Common Shares (Shares) | Common Shares (Amount) | Retained Deficit | Accumulated Other Comprehensive Income (loss) | Noncontrolling Interests | Preferred Shares of a Subsidiary Company | Total Shareholders' Equity |
|---|---|---|---|---|---|---|---|
| December 31, 2011 | 113.6 | $ 1,217.3 | $ (320.6) | $ (5.2) | $ 3.0 | $ 221.3 | $ 1,115.8 |
| Net (loss) income | | | (112.8) | | | 13.1 | (99.7) |
| Common shares issuance, net of issuance costs | 5.5 | 66.3 | | | | | 66.3 |
| Common shares issued for Equity Incentive Plan | | 0.1 | | | | | 0.1 |
| Common shares issued for LTIP | 0.2 | 1.8 | | | | | 1.8 |
| Common shares issued for DRIP | 0.2 | | | | | | |
| Noncontrolling interests | | | | | 233.0 | | 233.0 |
| Loss from noncontrolling interests | | | | | (0.6) | | (0.6) |
| Dividends declared on common shares | | | (131.8) | | | | (131.8) |
| Dividends declared on preferred shares of a subsidiary company | | | | | | (13.1) | (13.1) |
| Foreign currency translation adjustments | | | | 15.9 | | | 15.9 |
| Defined benefit plan, net of tax of $0.8 million | | | | (1.3) | | | (1.3) |
| December 31, 2012 | 119.5 | $ 1,285.5 | $ (565.2) | $ 9.4 | $ 235.4 | $ 221.3 | $ 1,186.4 |
| Net (loss) income | | | (33.0) | | | 12.6 | (20.4) |
| Common shares issued for LTIP | 0.1 | 0.6 | | | | | 0.6 |
| Common shares issued for DRIP | 0.6 | | | | | | |
| Noncontrolling interests | | | | | 43.3 | | 43.3 |
| Loss from noncontrolling interests | | | | | (3.4) | | (3.4) |
| Dividends declared on common shares | | | (57.2) | | | | (57.2) |
| Dividends paid to noncontrolling interests | | | | | (8.9) | | (8.9) |
| Dividends declared on preferred shares of a subsidiary company | | | | | | (12.6) | (12.6) |
| Unrealized gain on hedging activities, net of tax of $1.0 million | | | | 1.6 | | | 1.6 |
| Foreign currency translation adjustments | | | | (34.8) | | | (34.8) |
| Defined benefit plan, net of tax of $1.0 million | | | | 1.4 | | | 1.4 |
| December 31, 2013 | 120.2 | $ 1,286.1 | $ (655.4) | $ (22.4) | $ 266.4 | $ 221.3 | $ 1,096.0 |
| Net (loss) income | | | (177.4) | | | 11.6 | (165.8) |
| Common shares issued for LTIP | 0.6 | 2.3 | | | | | 2.3 |
| Common shares issued for DRIP | 0.5 | | | | | | |
| Loss from noncontrolling interests | | | | | (16.4) | | (16.4) |
| Dividends declared on common shares | | | (31.1) | | | | (31.1) |
| Dividends paid to noncontrolling interests | | | | | (11.0) | | (11.0) |
| of a subsidiary company | | | | | | (11.6) | (11.6) |
| Unrealized gain on hedging activities, net of tax of $0.3 million | | | | (0.1) | | | (0.1) |
| Foreign currency translation adjustments | | | | (44.1) | | | (44.1) |
| Defined benefit plan, net of tax of $0.6 million | | | | (1.7) | | | (1.7) |
| December 31, 2014 | 121.3 | $ 1,288.4 | $ (863.9) | $ (68.3) | $ 239.0 | $ 221.3 | $ 816.5 |

See accompanying notes to consolidated financial statements.

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**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

**(in millions of U.S. dollars)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2014** | **2013** | **2012** |
| Cash flows from operating activities: | | | |
| Net loss | $ (182.2) | $ (23.8) | $ (100.3) |
| Adjustments to reconcile to net cash provided by operating activities: | | | |
| Depreciation and amortization | 162.6 | 176.4 | 157.2 |
| Loss from discontinued operations | | 32.8 | |
| (Gain) loss on sale of assets & other charges | (2.9) | (5.1) | 0.8 |
| Long-term incentive plan expense | 3.5 | 2.2 | 2.5 |
| Long-lived asset and goodwill impairment charges | 106.6 | 39.7 | 60.5 |
| Gain on sale of equity investments | (8.6) | (30.4) | (0.6) |
| Equity in earnings from unconsolidated affiliates | (25.8) | (26.9) | (25.7) |
| Distributions from unconsolidated affiliates | 76.2 | 40.9 | 38.4 |
| Unrealized foreign exchange (gain) loss | (38.8) | (13.0) | 19.0 |
| Change in fair value of derivative instruments | 8.7 | (60.2) | 46.7 |
| Change in deferred income taxes | (15.7) | (27.3) | (34.1) |
| Change in other operating balances | | | |
| Accounts receivable | 6.9 | 3.4 | 2.3 |
| Inventory | (3.3) | 0.8 | (6.2) |
| Prepayments, refundable income taxes and other assets | 21.1 | 51.5 | (13.3) |
| Accounts payable | (4.1) | (8.4) | 21.1 |
| Accruals and other liabilities | (39.2) | (0.2) | (1.2) |
| Cash provided by operating activities | 65.0 | 152.4 | 167.1 |
| Cash flows provided by (used in) investing activities: | | | |
| Change in restricted cash | 72.6 | (93.7) | (11.6) |
| Proceeds from sale of assets and equity investments, net | 9.5 | 182.6 | 27.9 |
| Cash paid for acquisitions and investments, net of cash acquired | | | (80.5) |
| Proceeds from treasury grants | | 103.2 | |
| Biomass development costs | | (0.2) | (0.5) |
| Construction in progress | | (39.3) | (456.2) |
| Purchase of property, plant and equipment | (13.4) | (5.5) | (2.9) |
| Cash provided by (used in) investing activities | 68.7 | 147.1 | (523.8) |
| Cash flows (used in) provided by financing activities: | | | |
| Proceeds from senior secured term loan facility | 600.0 | | |
| Proceeds from issuance of convertible debentures | | | 230.6 |
| Proceeds from issuance of equity, net of offering costs | | (1.0) | 66.3 |
| Proceeds from project-level debt | | 20.8 | 291.9 |
| Repayment of corporate and project-level debt | (639.8) | (118.8) | (284.8) |
| Repayment of convertible debentures | (43.0) | | |
| Payments for revolving credit facility borrowings | | (67.0) | (60.8) |
| Proceeds from revolving credit facility borrowings | | | 69.8 |
| Deferred financing costs | (39.0) | (2.8) | (31.2) |
| Equity contribution from noncontrolling interest | | 44.6 | 225.0 |
| Dividends paid to common shareholders | (34.9) | (65.1) | (131.0) |
| Dividends paid to noncontrolling interests | (25.7) | (18.3) | (13.1) |
| Cash (used in) provided by financing activities | (182.4) | (207.6) | 362.7 |
| Net (decrease) increase in cash and cash equivalents | (48.7) | 91.9 | 6.0 |
| Less cash at discontinued operations | | | (6.5) |
| Cash and cash equivalents at beginning of period at discontinued operations | | 6.5 | |
| Cash and cash equivalents at beginning of period | 158.6 | 60.2 | 60.7 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Cash and cash equivalents at end of period | $ | 109.9 | $ | 158.6 | $ | 60.2 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Supplemental cash flow information | | | | | | |
| Interest paid | $ | 168.8 | $ | 130.4 | $ | 40.2 |
| Income taxes paid, net | $ | 3.8 | $ | 5.9 | $ | 1.1 |
| Accruals for construction in progress | $ | | $ | 8.9 | $ | 4.1 |

See accompanying notes to consolidated financial statements.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**(in millions U.S. dollars, except per-share amounts)**

**1. Nature of business**

***General***

Atlantic Power owns and operates a diverse fleet of power generation assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. As of December 31, 2014, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,945 megawatts ("MW") in which our aggregate ownership interest is approximately 2,024 MW. Our current portfolio consists of interests in twenty-eight operational power generation projects across eleven states in the United States and two provinces in Canada. Twenty of our projects are majority-owned subsidiaries.

Atlantic Power is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the Toronto Stock Exchange under the symbol "ATP" and on the New York Stock Exchange under the symbol "AT." Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 Canada and our headquarters is located at One Federal Street, 30$^{th}$ Floor, Boston, Massachusetts 02110, USA.

**2. Summary of significant accounting policies**

(a) Principles of consolidation and basis of presentation:

The accompanying consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the consolidated accounts and operations of our subsidiaries in which we have a controlling financial interest. The usual condition for a controlling financial interest is ownership of the majority of the voting interest of an entity. However, a controlling financial interest may also exist in entities, such as a variable interest entity, through arrangements that do not involve controlling voting interests.

We apply the standard that requires consolidation of variable interest entities ("VIEs"), for which we are the primary beneficiary. The guidance requires a variable interest holder to consolidate a VIE if that party has both the power to direct the activities that most significantly impact the entities' economic performance, as well as either the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE. We have determined that our equity investments are not VIEs by evaluating their design and capital structure. Accordingly, we use the equity method of accounting for all of our investments in which we do not have an economic controlling interest. We eliminate all intercompany accounts and transactions in consolidation.

(b) Cash and cash equivalents:

Cash and cash equivalents include cash deposited at banks and highly liquid investments with original maturities of 90 days or less when purchased.

(c) Restricted cash:

Restricted cash represents cash and cash equivalents that are maintained by the projects or corporate to support payments for maintenance costs and meet project level and corporate contractual

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

debt obligations. Restricted cash is classified as a current or long-term asset based on the timing and nature of when or how the cash is expected to be used or when the restrictions are expected to lapse.

(d) Deferred financing costs:

Deferred financing costs represent costs to obtain long-term financing and are amortized using the effective interest method over the term of the related debt which ranges from 4 to 22 years. The net carrying amount of deferred financing costs recorded on the consolidated balance sheets was $64.2 million and $41.7 million at December 31, 2014 and 2013, respectively. Interest expense from the amortization of deferred finance costs for the years ended December 31, 2014, 2013, and 2012 was $16.5 million, $8.0 million, and $4.4 million, respectively.

(e) Inventory:

Inventory represents small parts and other consumables and fuel, the majority of which is consumed by our projects in provision of their services, and are valued at the lower of cost or net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs.

(f) 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, up to 45 years. Significant additions or improvements extending asset lives are capitalized as incurred, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred.

(g) Project development costs and capitalized interest:

Project development costs are expensed in the preliminary stages of a project and capitalized as intangible assets when the project is deemed to be commercially viable. Commercial viability is determined by one or a series of actions including among others, obtaining a PPA.

Interest incurred on funds borrowed to finance capital projects is capitalized, until the project under construction is ready for its intended use. The amount of interest capitalized for the years ended December 31, 2014, 2013, and 2012 was $0.0 million, $1.9 million, and $17.0 million, respectively.

When a project is available for operations, capitalized interest and project development costs are reclassified to property, plant and equipment and amortized on a straight-line basis over the estimated useful life of the project's related assets. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

(h) Other intangible assets:

Other intangible assets include PPAs and fuel supply agreements at our projects, as well as capitalized development costs. PPAs are valued at the time of acquisition based on the contract prices under the PPAs compared to projected market prices. Fuel supply agreements are valued at the time of acquisition based on the contract prices under the fuel supply agreement compared to projected market prices. The balances are presented net of accumulated amortization in the consolidated balance sheets. Amortization is recorded on a straight-line basis over the remaining term of the agreement.

(i) Investments accounted for by the equity method:

We have investments in entities that own power producing assets with the objective of generating cash flow. The equity method of accounting is applied to such investments in affiliates, which include joint ventures, partnerships, and limited liability companies because the ownership structure prevents us from exercising a controlling influence over the operating and financial policies of the projects. Our investments in partnerships and limited liability companies with 50% or less ownership, but greater than 5% ownership in which we do not have a controlling interest are accounted for under the equity method of accounting. We apply the equity method of accounting to investments in limited partnerships and limited liability companies with greater than 5% ownership because our influence over the investment's operating and financial policies is considered to be more than minor.

Under the equity method, equity in pre-tax income or losses of our investments is reflected as equity in earnings of unconsolidated affiliates. The cash flows that are distributed to us from these unconsolidated affiliates are directly related to the operations of the affiliates' power producing assets and are classified as cash flows from operating activities in the consolidated statements of cash flows. We record the return of our investments in equity investees as cash flows from investing activities. Cash flows from equity investees are considered a return of capital when distributions are generated from proceeds of either the sale of our investment in its entirety or a sale by the investee of all or a portion of its capital assets.

(j) Impairment of long-lived assets, non-amortizing intangible assets and equity method investments:

Long-lived assets, such as property, plant and equipment, and other intangible assets and liabilities subject to depreciation and amortization, are reviewed for impairment annually or 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 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 its fair value.

Investments in and the operating results of 50%-or-less owned entities not consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in such unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. We also review a project for impairment at the earlier of executing a new PPA (or other arrangement) or six months prior to the expiration of an existing PPA. Factors such as the business

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

climate, including current energy and market conditions, environmental regulation, the condition of assets, and the ability to secure new PPAs are considered when evaluating long-lived assets for impairment. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment or, where applicable, estimated sales proceeds that are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long-term investments. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

(k) 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 our reporting units that are expected to benefit from the synergies of the business combination.

Goodwill is not amortized and is tested for impairment, annually in the fourth quarter, or more frequently if events or changes in circumstances indicate that the asset might be impaired. In September 2011, the Financial Accounting Standards Board ("FASB") issued ASU 2011-08 "Intangibles Goodwill and Other." This guidance on testing goodwill provides the option to first perform a qualitative assessment ("step zero") to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If we determine that this is the case, we are required to perform a two-step goodwill impairment test, as described below, to identify potential goodwill impairment and measure the amount of goodwill impairment loss to be recognized for that reporting unit (if any). If we determine that the fair value of a reporting unit is not less than its carrying amount, no impairment is recorded.

In our test, we first perform step zero to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (i.e. more than 50%) that the fair value of a reporting unit is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions, industry and market considerations, cost factors, overall financial performance and other relevant entity-specific events. If the qualitative assessment determines that an impairment is more likely than not, then we perform a two-step quantitative impairment test. In the first step of the quantitative analysis, 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

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

the fair value of the reporting unit as if it were 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 recorded in the consolidated statements of operations.

(l) Discontinued operations:

Long-lived assets or disposal groups are classified as discontinued operations in the period in which all of the required criteria are met. The criteria include, among others, existence of a qualified plan to dispose of an asset or disposal group, an assessment that completion of a sale within one year is probable and approval of the appropriate level of management. Upon completion of the transaction, the operations and cash flows of the disposal group must be eliminated from our ongoing operations, and the disposal group must not have any significant continuing involvement with us. Discontinued operations are reported at the lower of the asset's carrying amount or fair value less cost to sell.

(m) Derivative financial instruments:

We use derivative financial instruments in the form of interest rate swaps and foreign exchange forward contracts to manage our current and anticipated exposure to fluctuations in interest rates and foreign currency exchange rates. We have 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 significant operating cost. We do not enter into derivative financial instruments for trading or speculative purposes. Certain derivative instruments qualify for a scope exception to fair value accounting because they are considered normal purchases or normal sales in the ordinary course of conducting business. This exception applies when we have the ability to, and it is probable that we will deliver or take delivery of the underlying physical commodity.

We have designated one of our interest rate swaps as a hedge of cash flows for accounting purposes. Tests are performed to evaluate hedge effectiveness and ineffectiveness at inception and on an ongoing basis, both retroactively and prospectively. Derivatives accounted for as hedges are recorded at fair value in the balance sheet. Unrealized gains or losses on derivatives designated as a hedge are deferred and recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. The ineffective portion of the cash flow hedge, if any, is immediately recognized in earnings.

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. The following table summarizes derivative financial instruments that are not designated as hedges for accounting purposes and the accounting treatment in the consolidated statements of operations of the changes in fair value and cash settlements of such derivative financial instrument:

| Derivative financial instrument | Classification of changes in fair value | Classification of cash settlements |
|---|---|---|
| Natural gas swaps | Changes in fair value of derivative instrument | Fuel expense |
| Fuel purchase agreements | Changes in fair value of derivative instrument | Fuel expense |
| Interest rate swaps | Changes in fair value of derivative instrument | Interest expense |
| Foreign currency forward contract | Foreign exchange (gain) loss | Foreign exchange (gain) loss |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

(n) Income taxes:

Income tax expense includes the current tax obligation or benefit and change in deferred income tax asset or liability for the period. We use the asset and liability method of accounting for deferred income taxes and record deferred income taxes for all significant temporary differences. Income tax benefits associated with uncertain tax positions are recognized when we determine that it is more-likely-than-not that the tax position will be ultimately sustained. Refer to Note 15 for more information.

(o) Revenue recognition:

We recognize energy sales revenue on a gross basis when electricity and steam are delivered under the terms of the related contracts. PPAs, steam purchase arrangements and energy services agreements are long-term contracts to sell power and steam on a predetermined basis.

*Energy* Energy revenue is recognized upon transmission to the customer. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in our consolidated statements of operations.

*Capacity* Capacity payments under the PPAs are recognized as the lesser of (1) the amount billable under the PPA or (2) an amount determined by the kilowatt hours made available during the period multiplied by the estimated average revenue per kilowatt hour over the term of the PPA.

(p) Power purchase arrangements containing a lease:

We have entered into PPAs to sell power at predetermined rates. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the project's property, plant and equipment in return for future payments. Such arrangements are classified as either capital or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property to the PPA counterparty are classified as direct financing leases.

Finance income related to leases or arrangements accounted for as direct financing leases is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is comprised of net minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying value of the leased property. Unearned finance income is deferred and recognized in net income (loss) over the lease term.

For PPAs accounted for as operating leases, we recognize lease income consistent with the recognition of energy revenue. When energy is delivered, we recognize lease income in energy revenue.

(q) Foreign currency translation and transaction gains and losses:

The local currency is the functional currency of our U.S. and Canadian projects. Our reporting currency is the U.S. dollar. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted-average rates of exchange for the period. The resulting currency translation adjustments are not

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

included in the determination of our statements of operations for the period, but are accumulated and reported as a separate component of shareholders' equity until sale of the net investment in the project takes place. Foreign currency transaction gains or losses are reported within foreign exchange (gain) loss in our statements of operations.

(r) Equity compensation plans:

The officers and certain other employees are eligible to participate in the Long-Term Incentive Plan ("LTIP"). Some of the notional units that vest are based, in part, on certain financial performance metrics and the total shareholder return of Atlantic Power compared to a group of peer companies. In addition, vesting of certain notional units for officers of Atlantic Power occurs on a three-year cliff basis; certain other notional units for officers and non-officers vest ratably.

Vested notional units are expected to be redeemed one-third in cash and two-thirds in shares of our common stock. Notional units granted that are expected to be redeemed in cash upon vesting are accounted for as liability awards. Notional units granted that are expected to be redeemed in common shares upon vesting are accounted for as equity awards. Unvested notional units are entitled to receive dividends equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested units are subject to forfeiture if the participant is not an employee at the vesting date or if we do not meet certain ongoing cash flow performance targets.

For awards that are subject to a performance-based vesting condition, the final number of notional units for officers that will vest, if any, at the end of the three-year vesting period is based on our achievement of certain financial performance metrics and meeting target levels of relative total shareholder return, which is the change in the value of an investment in our common stock, including reinvestment of dividends, compared to that of a peer group of companies during the performance period. The total number of notional units vesting will range from zero up to a maximum 150% of the number of notional units in the executives' accounts on the vesting date for that award, depending on the level of achievement of relative total shareholder return during the measurement period.

Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and the fair value of the award at each balance sheet date for notional units accounted for as liability awards. The fair value of awards granted under the LTIP with market vesting conditions is based upon a Monte Carlo simulation model on the grant date. Compensation expense is recognized regardless of the relative total shareholder return performance, provided that the LTIP participant remains employed by Atlantic Power.

(s) Asset retirement obligations:

The fair value for an asset retirement obligation is recorded in the period in which it is incurred. Retirement obligations associated with long-lived assets are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel, and for which the timing and/or method of settlement may be conditional on a future event. When the liability is initially recorded, we capitalize the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, we either settle the obligation for its recorded amount or incur a gain or loss.

(t) Pensions:

We offer pension benefits to certain employees through a defined benefit pension plan. We recognize the funded status of our defined benefit plan in the consolidated balance sheets in other long-term liabilities and record an offset to other comprehensive income (loss). In addition, we also recognize on an after-tax basis, as a component of other comprehensive income (loss), gains and losses as well as all prior service costs that have not been included as part of our net periodic benefit cost. The determination of our obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. Our actuarial consultants use assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of our pension obligation or expense recorded.

(u) Business combinations:

We account for our business combinations in accordance with the acquisition method of accounting, which requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also recognizes and measures the goodwill acquired or a gain from a bargain purchase in the business combination and determines what information to disclose to enable users of an entity's financial statements to evaluate the nature and financial effects of the business combination. In addition, transaction costs are expensed as incurred.

(v) Concentration of credit risk:

The financial instruments that potentially expose us to credit risk consist primarily of cash and cash equivalents, restricted cash, derivative instruments and accounts receivable. Cash and restricted cash are held by major financial institutions that are also counterparties to our derivative instruments. We have long-term agreements to sell electricity, gas and steam to public utilities and corporations. We have exposure to trends within the energy industry, including declines in the creditworthiness of our customers. We do not normally require collateral or other security to support energy-related accounts receivable. We do not believe there is significant credit risk associated with accounts receivable due to the credit worthiness and payment history of our customers. See Note 22, *Segment and geographic information*, for a further discussion of customer concentrations.

(w) Use of estimates:

The preparation of financial statements requires us 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, we have made a number

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment, valuation of goodwill, intangible assets and liabilities related to PPAs and fuel supply agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the fair value of financial instruments and derivatives, pension obligations, asset retirement obligations, the allocation of taxable income and losses, tax credits and cash distributions using the hypothetical liquidation book value ("HLBV") method and the fair values of acquired assets,. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(x) Federal grants:

Certain projects have received grants and similar government incentives for the construction of renewable energy facilities. Proceeds from these grants reduced the basis of the corresponding asset balance when the cash was received.

(y) Allocation of net income or losses to certain investors using HLBV:

For consolidated investments with flip structures that allocate taxable income and losses, tax credits and cash distributions under allocation provisions of agreements with third-party investors, net income or loss is allocated to third-party investors for accounting purposes using the hypothetical liquidation book value method. HLBV is a balance sheet oriented approach that calculates the change in the claims of each partner on the net assets of the investment at the beginning and end of each period. Each partner's claim is equal to the amount each party would receive or pay if the net assets of the investment were to liquidate at book value and the resulting cash was then distributed to investors in accordance with their respective liquidation preferences. We report the net income or loss attributable to the third-party investors as income (loss) attributable to noncontrolling interests in the consolidated statements of operations.

(z) Reclassifications

Prior year amounts for restricted cash have been reclassified from current to long-term to conform to the current period presentation.

(aa) Recently issued accounting standards:

*Adopted*

In July 2013, the FASB issued changes to the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. These changes require an entity to present an unrecognized tax benefit as a liability in the financial statements if (i) a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

would result from the disallowance of a tax position, or (ii) the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset to settle any additional income taxes that would result from the disallowance of a tax position. Otherwise, an unrecognized tax benefit is required to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. Previously, there was diversity in practice as no explicit guidance existed. These changes became effective for us on January 1, 2014 and did not have a material impact on the consolidated financial statements.

In March 2013, the FASB issued changes to a parent entity's accounting for the cumulative translation adjustment upon derecognition of certain subsidiaries or groups of assets within a foreign entity or of an investment in a foreign entity. A parent entity is required to release any related cumulative foreign currency translation adjustment from accumulated other comprehensive income (loss) into net income (loss) in the following circumstances: (i) a parent entity ceases to have a controlling financial interest in a subsidiary or group of assets that is a business within a foreign entity if the sale or transfer results in the complete or substantially complete liquidation of the foreign entity in which the subsidiary or group of assets had resided; (ii) a partial sale of an equity method investment that is a foreign entity; (iii) a partial sale of an equity method investment that is not a foreign entity whereby the partial sale represents a complete or substantially complete liquidation of the foreign entity that held the equity method investment; and (iv) the sale of an investment in a foreign entity. These changes became effective for us on January 1, 2014 and had no impact on the consolidated financial statements.

In February 2013, the FASB issued changes to the accounting for obligations resulting from joint and several liability arrangements. These changes require an entity to measure such obligations for which the total amount of the obligation is fixed at the reporting date as the sum of (i) the amount the reporting entity agreed to pay on the basis of its arrangement among its co- obligors, and (ii) any additional amount the reporting entity expects to pay on behalf of its co-obligors. An entity will also be required to disclose the nature and amount of the obligation as well as other information about those obligations. Examples of obligations subject to these requirements are debt arrangements and settled litigation and judicial rulings. These changes became effective for us on January 1, 2014 and had no impact on the consolidated financial statements.

On January 1, 2013, we adopted changes issued by the FASB to the reporting of amounts reclassified out of accumulated other comprehensive income. These changes require an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required to be reclassified in its entirety to net income. For other amounts that are not required to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures that provide additional detail about those amounts. These requirements are to be applied to each component of accumulated other comprehensive income. Other than the additional disclosure requirements, the adoption of these changes had no impact on the consolidated financial statements.

On January 1, 2013, we adopted changes issued by the FASB to the testing of indefinite-lived intangible assets for impairment, similar to the goodwill changes issued in September 2011. These changes provide an entity the option to first assess qualitative factors to determine whether the

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of an indefinite-lived intangible asset is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions; industry and market considerations; cost factors; overall financial performance; and other relevant entity-specific events. If an entity elects to perform a qualitative assessment and determines that an impairment is more likely than not, the entity is then required to perform the existing two-step quantitative impairment test, otherwise no further analysis is required. An entity also may elect not to perform the qualitative assessment and, instead, proceed directly to the two-step quantitative impairment test. The adoption of these changes had no impact on the consolidated financial statements.

In July 2012, the Financial Accounting Standards Board ("FASB") issued changes to the testing of indefinite-lived intangible assets for impairment, similar to the goodwill changes issued in September 2011. These changes provide an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of an indefinite-lived intangible asset is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions; industry and market considerations; cost factors; overall financial performance; and other relevant entity-specific events. If an entity elects to perform a qualitative assessment and determines that an impairment is more likely than not, the entity is then required to perform the existing two-step quantitative impairment test, otherwise no further analysis is required. An entity also may elect not to perform the qualitative assessment and, instead, proceed directly to the two-step quantitative impairment test. These changes became effective for us for any indefinite-lived intangible asset impairment test performed on January 1, 2013 or later. The adoption of these changes did not impact the consolidated financial statements.

In December 2011, the FASB issued changes to the disclosure of offsetting assets and liabilities. These changes require an entity to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The enhanced disclosures will enable users of an entity's financial statements to understand and evaluate the effect or potential effect of master netting arrangements on an entity's financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. These changes became effective for us on January 1, 2013. Other than the additional disclosure requirements, the adoption of these changes did not impact the consolidated financial statements.

On January 1, 2012, we adopted changes issued by the FASB to conform existing guidance regarding fair value measurement and disclosure between GAAP and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and amend certain principles or requirements for measuring fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio;

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

application of premiums and discounts in a fair value measurement; and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. The adoption of these changes had no impact on our consolidated financial statements.

On January 1, 2012, we adopted changes issued by the FASB to the presentation of comprehensive income (loss). These changes give an entity the option to present the total of comprehensive income (loss), the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income (loss) or in two separate but consecutive statements; the option to present components of other comprehensive income (loss) as part of the statement of changes in shareholders' equity was eliminated. The items that must be reported in other comprehensive income (loss) or when an item of other comprehensive income (loss) must be reclassified to net income were not changed. Additionally, no changes were made to the calculation and presentation of earnings per share. We elected to present the two- statement option. Other than the change in presentation, the adoption of these changes had no impact on our consolidated financial statements.

*Issued*

In August 2014, the FASB issued changes to the disclosure of uncertainties about an entity's ability to continue as a going concern. Under GAAP, continuation of a reporting entity as a going concern is presumed as the basis for preparing financial statements unless and until the entity's liquidation becomes imminent. Even if an entity's liquidation is not imminent, there may be conditions or events that raise substantial doubt about the entity's ability to continue as a going concern. Because there is no guidance in GAAP about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern or to provide related note disclosures, there is diversity in practice whether, when, and how an entity discloses the relevant conditions and events in its financial statements. As a result, these changes require an entity's management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that financial statements are issued. Substantial doubt is defined as an indication that it is probable that an entity will be unable to meet its obligations as they become due within one year after the date that financial statements are issued. If management has concluded that substantial doubt exists, then the following disclosures should be made in the financial statements: (i) principal conditions or events that raised the substantial doubt, (ii) management's evaluation of the significance of those conditions or events in relation to the entity's ability to meet its obligations, (iii) management's plans that alleviated the initial substantial doubt or, if substantial doubt was not alleviated, management's plans that are intended to at least mitigate the conditions or events that raise substantial doubt, and (iv) if the latter in (iii) is disclosed, an explicit statement that there is substantial doubt about the entity's ability to continue as a going concern. These changes become effective for us for financial statements issued after December 15, 2016. We are currently evaluating the potential impact of these changes on the consolidated financial statements. Subsequent to adoption, this guidance will need to be applied by management at the end of each annual period and interim period therein to determine what, if any, impact there will be on the consolidated financial statements in a given reporting period.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

In April 2014, the FASB issued changes to reporting discontinued operations and disclosures of disposals of components of an entity. These changes require a disposal of a component to meet a higher threshold in order to be reported as a discontinued operation in an entity's financial statements. The threshold is defined as a strategic shift that has, or will have, a major effect on an entity's operations and financial results such as a disposal of a major geographical area or a major line of business. Additionally, the following two criteria have been removed from consideration of whether a component meets the requirements for discontinued operations presentation: (i) the operations and cash flows of a disposal component have been or will be eliminated from the ongoing operations of an entity as a result of the disposal transaction, and (ii) an entity will not have any significant continuing involvement in the operations of the disposal component after the disposal transaction. Furthermore, equity method investments now may qualify for discontinued operations presentation. These changes also require expanded disclosures for all disposals of components of an entity, whether or not the threshold for reporting as a discontinued operation is met, related to profit or loss information and/or asset and liability information of the component. These changes become effective on January 1, 2015. The adoption of these changes will not have an immediate impact on the consolidated financial statements. This guidance will need to be considered in the event that we initiate a disposal transaction.

In May 2014, the FASB issued changes to the recognition of revenue from contracts with customers. These changes created a comprehensive framework for all entities in all industries to apply in the determination of when to recognize revenue, and, therefore, supersede virtually all existing revenue recognition requirements and guidance. This framework is expected to result in less complex guidance in application while providing a consistent and comparable methodology for revenue recognition. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this principle, an entity should apply the following steps: (i) identify the contract(s) with a customer, (ii) identify the performance obligations in the contract(s), (iii) determine the transaction price, (iv) allocate the transaction price to the performance obligations in the contract(s), and (v) recognize revenue when, or as, the entity satisfies a performance obligation. These changes become effective on January 1, 2017. We are currently evaluating the potential impact of these changes on the consolidated financial statements.

**3. Acquisitions and divestments**

***2012 Acquisitions***

(a) Ridgeline

On November 5, 2012 we entered into a purchase and sale agreement to acquire a 100% ownership interest in Ridgeline for approximately $81.3 million. Ridgeline develops, constructs and operates wind and solar energy projects across the United States. As a result of the acquisition, we increased our ownership in Rockland Wind Farm, LLC. ("Rockland") from a 30% to a 50% managing member interest (which is 100% consolidated) and our net generation capacity increased from 24 to 40 MW. We also acquired a 12.5% equity ownership in Goshen, a 124.5 MW (16 MW, net) wind project operating in Idaho. Additionally, we purchased a 100% ownership interest in Meadow Creek, a

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**3. Acquisitions and divestments (Continued)**

119.7 MW wind project operating in Idaho, which completed construction and became operational on December 22, 2012.

We closed this transaction on December 31, 2012 and financed the acquisition through the issuance of Cdn$100 million (approximately Cdn$95 million after underwriting and transaction costs) aggregate principal amount of series D extendible convertible unsecured subordinated debentures (the "December 2012 Debentures").

Our acquisition of Ridgeline was accounted for under the acquisition method of accounting as of the transaction closing date. The final purchase price allocation for the business combination is as follows:

| | | |
|---|---|---|
| **Fair value of consideration transferred:** | | |
| Cash | $ | 81.3 |
| Other items to be allocated to identifiable assets acquired and liabilities assumed: | | |
| Fair value of our investment in Rockland at the acquisition date | | 12.1 |
| Loss recognized on the step acquisition | | (7.4) |
| Total purchase price | $ | 86.0 |

| | | |
|---|---|---|
| **Final purchase price allocation** | | |
| Cash | $ | 1.0 |
| Working capital | | (8.1) |
| Property, plant, and equipment | | 373.9 |
| Deferred tax asset | | 9.6 |
| Other long-term assets | | 36.0 |
| Long-term debt | | (295.5) |
| Interest rate swaps | | (21.6) |
| Other long-term liabilities | | (1.3) |
| Minority interest | | (8.0) |
| Total identifiable net assets | $ | 86.0 |

The fair values of the assets acquired and liabilities assumed were estimated by applying an income approach using the discounted cash flow method. These measurements were based on significant inputs not observable in the market and thus represent a level 3 fair value measurement. The primary considerations and assumptions that affected the discounted cash flows included the operational characteristics and financial forecasts of acquired facilities, remaining useful lives and discount rates based on the weighted average cost of capital ("WAAC") adjusted for the risk and characteristics of each plant.

During the fourth quarter of 2013, we adjusted the fair value of the net deferred taxes recorded in the preliminary purchase price allocation. The adjustment was based on the final determination of deferred taxes on net operating loss carryforwards and other tax attributes that were acquired as part of the Ridgeline acquisition. As a result, the opening deferred tax liability of $14.2 million was adjusted

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**3. Acquisitions and divestments (Continued)**

to a deferred tax asset of $9.6 million with a corresponding reduction to property, plant and equipment of $23.9 million. The Ridgeline purchase price allocation was final at December 31, 2013.

(b) Canadian Hills

On January 31, 2012, Atlantic Oklahoma Wind, LLC ("Atlantic OW"), a Delaware limited liability company and our wholly owned subsidiary, entered into a purchase and sale agreement with Apex Wind Energy Holdings, LLC, a Delaware limited liability company ("Apex"), pursuant to which Atlantic OW acquired a 51% interest in Canadian Hills Wind, LLC, an Oklahoma limited liability company ("Canadian Hills") for a nominal sum. Canadian Hills is the owner of a 300 MW wind energy project in the state of Oklahoma.

On March 30, 2012, we completed the purchase of an additional 48% interest in Canadian Hills for a nominal amount, bringing our total interest in the project to 99%. Apex retained a 1% interest in the project. We also closed a $310 million non-recourse, project-level construction financing facility for the project, which included a $290 million construction loan and a $20 million 5-year letter of credit facility. In July 2012, we funded approximately $190 million of our equity contribution (net of financing costs). In December 2012, the project received tax equity investments in aggregate of $225 million from a consortium of four institutional tax equity investors along with an approximately $44 million tax equity investment of our own. The project's outstanding construction loan was repaid by the proceeds from these tax equity investments, decreasing the project's short-term debt by $265 million as of December 31, 2012. On May 2, 2013, we syndicated our $44 million tax equity investment in Canadian Hills to an institutional investor and received net cash proceeds of $42.1 million. The syndication of our interest completed the sale of 100% of Canadian Hills' $269 million of tax equity interests.

The acquisition of Canadian Hills was accounted for as an asset purchase and is consolidated in our consolidated balance sheets at December 31, 2014 and 2013. We own 99% of the project and consolidate it in our consolidated financial statements. Income attributable to noncontrolling interests is allocated utilizing HLBV.

***2014 Divestments***

(a) Delta-Person

In December 2012, we and the other owners of Delta-Person entered into a purchase and sale agreement with BHB Power, LLC and Public Service Company of New Mexico to sell the project for approximately $37.2 million including working capital adjustments. The sale of Delta-Person closed in July 2014 resulting in a gain on sale of approximately $8.6 million that was recorded in the consolidated statement of operations for the year ended December 31, 2014. We received net cash proceeds for our ownership interest of approximately $7.2 million in the aggregate. We expect to receive an additional $1.4 million of cash proceeds held in escrow for up to twelve months after the close of the transaction. We intend to use the net proceeds from the sale for general corporate purposes.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**3. Acquisitions and divestments (Continued)**

(b) Greeley

In March 2014, we closed a transaction with Initium Power Partners, LLC. ("Initium"), whereby Initium agreed to purchase all of the issued and outstanding membership interests in Greeley for approximately $1.0 million. We recorded a $2.1 million non-cash gain on the sale in the consolidated statement of operations for the year ended December 31, 2014. Greeley is accounted for as a component of discontinued operations in the consolidated statements of operations for the year ended December 31, 2014, 2013, and 2012.

***2013 Divestments***

(a) Rollcast

On November 5, 2013, we completed the sale of our 60% interest in Rollcast to its remaining shareholders. As consideration for the sale, we were assigned asset management contracts valued at $0.5 million for the Cadillac and Piedmont projects as well as the remaining 2% ownership interest in Piedmont bringing our total ownership to 100%. In return, we paid $0.5 million in cash to the minority owner and forgave an outstanding $1.0 million loan that was provided by us to Rollcast to fund working capital during 2013. We recorded a $1.0 million gain on sale which is recorded in other income, net in the consolidated statements of operations for the year ended December 31, 2013. Rollcast's net loss is recorded as loss from discontinued operations in the consolidated statements of operations for the years ended December 31, 2013 and 2012.

(b) Gregory

On April 2, 2013, we and the other owners of Gregory entered into a purchase and sale agreement with an affiliate of NRG Energy, Inc. to sell the project for approximately $274.2 million, including working capital adjustments. The sale of Gregory closed on August 7, 2013 resulting in a gain on sale of $30.4 million that was recorded in the consolidated statements of operations for the year ended December 31, 2013. We received net cash proceeds for our ownership interest of approximately $34.6 million in the aggregate, after repayment of project- level debt and transaction expenses. As of December 31, 2014, approximately $0.9 million of these proceeds remain in escrow for any post-closing adjustments that may arise subsequent to the closing date. We used the net proceeds from the sale for general corporate purposes.

(c) Auburndale, Lake and Pasco

On January 30, 2013, we entered into a purchase and sale agreement for the sale of our Auburndale Power Partners, L.P. ("Auburndale"), Lake CoGen, Ltd. ("Lake") and Pasco CoGen, Ltd. ("Pasco") projects (collectively, the "Florida Projects") for approximately $140.0 million, with working capital adjustments. The sale closed on April 12, 2013 and we received net cash proceeds of approximately $117.0 million in the aggregate, after repayment of project-level debt at Auburndale and settlement of all outstanding natural gas swap agreements at Lake and Auburndale. This includes approximately $92.0 million received at closing and cash distributions from the Florida Projects of approximately $25.0 million received since January 1, 2013. We used a portion of the net proceeds from the sale to fully repay our senior credit facility, which had an outstanding balance of approximately

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**3. Acquisitions and divestments (Continued)**

$64.1 million on the closing date. The remaining cash proceeds were used for general corporate purposes. The Florida Projects are accounted for as a component of discontinued operations in the consolidated statements of operations for the years ended December 31, 2013 and 2012. See Note 21, *Discontinued operations*, for further information.

(d) Path 15

On March 11, 2013, we entered into a purchase and sales agreement with Duke Energy Corporation and American Transmission Co., to sell our interests in the Path 15 transmission line ("Path 15"). The sale closed on April 30, 2013 and we received net cash proceeds from the sale, including working capital adjustments, of approximately $52.0 million, plus a management agreement termination fee of $4.0 million, for a total sale price of approximately $56.0 million. The cash proceeds were used for general corporate purposes. All project level debt issued by Path 15, totaling $137.2 million, transferred with the sale. Path 15 is accounted for as a component of discontinued operations in the consolidated statements of operations for the years ended December 31, 2013 and 2012. See Note 21, *Discontinued operations*, for further information.

***2012 Divestments***

(a) Badger Creek

On August 2, 2012, we entered into a purchase and sale agreement for the sale of our 50% ownership interest in the Badger Creek project. On September 4, 2012, the transaction closed and we received gross proceeds of $3.7 million. As a result of the sale, we recorded an impairment charge in 2012 of $3.0 million in equity in earnings from unconsolidated affiliates in the consolidated statements of operations.

(b) Primary Energy Recycling Corporation

On February 16, 2012, we entered into an agreement with Primary Energy Recycling Corporation ("Primary Energy" or "PERC"), whereby PERC agreed to purchase our 7,462,830.33 common membership interests in PERH (14.3% of PERH total interests) for approximately $24.2 million, plus a management agreement termination fee of approximately $6.0 million, for a total sale price of $30.2 million. The transaction closed in May 2012 and we recorded a $0.6 million gain on sale of our equity investment.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

## 4. Changes in accumulated other comprehensive loss by component

The changes in accumulated other comprehensive loss by component were as follows:

| | Year Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| **Foreign currency translation** | | | |
| Balance at beginning of period | $ (22.2) | $ 12.6 | $ (3.3) |
| Other comprehensive loss: | | | |
| Foreign currency translation adjustments[(1)] | (44.1) | (34.8) | 15.9 |
| Balance at end of period | $ (66.3) | $ (22.2) | $ 12.6 |
| **Pension** | | | |
| Balance at beginning of period | $ (0.4) | $ (1.8) | $ (0.5) |
| Other comprehensive income (loss): | | | |
| Unrecognized net actuarial gain (loss) | (2.3) | 2.4 | (2.1) |
| Tax benefit (expense) | 0.6 | (0.7) | 0.8 |
| Total Other comprehensive (loss) income before reclassifications, net of tax | (1.7) | 1.7 | (1.3) |
| Amortization of net actuarial loss | | (0.4) | |
| Tax benefit | | 0.1 | |
| Total amount reclassified from Accumulated other comprehensive loss, net of tax | | (0.3) | |
| Total Other comprehensive (loss) income | (1.7) | 1.4 | (1.3) |
| Balance at end of period | $ (2.1) | $ (0.4) | $ (1.8) |
| **Cash flow hedges** | | | |
| Balance at beginning of period | $ 0.2 | $ (1.4) | $ (1.4) |
| Other comprehensive income (loss): | | | |
| Net change from periodic revaluations | (1.7) | 1.2 | (1.5) |
| Tax benefit (expense) | 0.7 | (0.5) | 0.6 |
| Total Other comprehensive (loss) income before reclassifications, net of tax | (1.0) | 0.7 | (0.9) |
| Net amount reclassified to earnings: | | | |
| Interest rate swaps[(2)] | 1.5 | 1.7 | 1.9 |
| Fuel commodity swaps[(3)] | | (0.2) | (0.4) |
| Sub-total | 1.5 | 1.5 | 1.5 |
| Tax benefit | (0.6) | (0.6) | (0.6) |
| Total amount reclassified from Accumulated other comprehensive loss, net of tax | 0.9 | 0.9 | 0.9 |
| Total Other comprehensive (loss) income | (0.1) | 1.6 | |
| Balance at end of period | $ 0.1 | $ 0.2 | $ (1.4) |

(1) In all periods presented, there were no tax impacts related to rate changes and no amounts were reclassified to earnings (loss).

(2) This amount was included in Interest expense, net on the accompanying consolidated statements of operations.

(3) A positive amount indicates a corresponding charge to earnings (loss) and a negative amount indicates a corresponding benefit to earnings (loss). These amounts were reflected on the accompanying consolidated statements of operations in the line items indicated in footnotes 1 and 2.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**5. Equity method investments in unconsolidated affiliates**

The following tables summarize our equity method investments in unconsolidated affiliates:

| Entity name | Percentage of Ownership as of December 31, 2014 | Carrying value as of December 31. 2014 | 2013 |
|---|---|---|---|
| Frederickson | 50.2% | $ 135.0 | $ 153.9 |
| Orlando Cogen, LP | 50.0% | 10.9 | 14.3 |
| Koma Kulshan Associates | 49.8% | 5.7 | 5.8 |
| Chambers Cogen, LP | 40.0% | 143.3 | 153.7 |
| Idaho Wind Partners 1, LLC | 27.6% | 30.2 | 33.2 |
| Selkirk Cogen Partners, LP | 18.5% | 12.0 | 24.4 |
| Goshen | 12.5% | 6.8 | 9.0 |
| Total | | $ 343.9 | $ 394.3 |

Equity (deficit) in earnings (loss) of equity method investments was as follows:

| Entity name | Year Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| Chambers Cogen, LP | $ 7.0 | $ 9.6 | $ 17.1 |
| Orlando Cogen, LP | 18.6 | 3.3 | 3.2 |
| Koma Kulshan Associates | 0.9 | 0.3 | 0.5 |
| Frederickson | 2.2 | 2.1 | 0.9 |
| Idaho Wind Partners 1, LLC | 0.9 | (0.3) | (0.2) |
| Selkirk Cogen Partners, LP | (3.2) | 8.7 | 7.6 |
| Goshen | (0.6) | 1.4 | |
| Delta-Person, LP[1] | | | |
| Gregory Power Partners, LP[2] | | 1.6 | (0.7) |
| Badger Creek Limited | | | (2.8) |
| Rockland Wind Farm[3] | | | (8.0) |
| PERH | | | (2.0) |
| Other | | 0.2 | (0.4) |
| Total | 25.8 | 26.9 | 15.2 |
| Distributions from equity method investments | (76.2) | (40.9) | (38.4) |
| Deficit in earnings (loss) of equity method investments, net of distributions | $ (50.4) | $ (14.0) | $ (23.2) |

(1) We closed on the sale of Delta-Person in July 2014, resulting in a gain on sale of approximately of $8.6 million, which is recorded in gain on sale of equity investments in the consolidated statements of operations for the year ended December 31, 2014.

(2)

We sold Gregory in August 2013, resulting in a gain on sale of approximately of $30.4 million, which is recorded in gain on sale of equity investments in the consolidated statements of operations for the year ended December 31, 2013.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**5. Equity method investments in unconsolidated affiliates (Continued)**

(3) Due to an ownership change from 30% to 50% as part of the Ridgeline acquisition during the fourth quarter of 2012, Rockland Wind Farm was consolidated as of December 31, 2012.

The following summarizes the financial position at December 31, 2014, 2013 and 2012, and operating results for the years ended December 31, 2014, 2013 and 2012, respectively, for our proportional ownership interest in equity method investments:

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| **Assets** | | | |
| Current assets | | | |
| Chambers | $ 14.4 | $ 11.8 | $ 16.1 |
| Selkirk | 12.2 | 12.9 | 12.9 |
| Other | 13.3 | 24.6 | 32.0 |
| Non-current assets | | | |
| Chambers | 213.4 | 224.0 | 235.2 |
| Selkirk | 1.8 | 14.1 | 26.0 |
| Other | 261.0 | 286.6 | 322.3 |
| | $ 516.1 | $ 574.0 | $ 644.5 |
| **Liabilities** | | | |
| Current liabilities | | | |
| Chambers | $ 3.5 | $ 4.4 | $ 15.2 |
| Selkirk | 1.3 | 2.3 | 4.8 |
| Other | 12.8 | 13.9 | 16.4 |
| Non-current liabilities | | | |
| Chambers | 81.0 | 77.7 | 81.8 |
| Selkirk | 0.7 | 0.3 | 0.3 |
| Other | 72.9 | 81.1 | 97.3 |
| | $ 172.2 | $ 179.7 | $ 215.8 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**5. Equity method investments in unconsolidated affiliates (Continued)**

| Operating results | 2014 | 2013 | 2012 |
|---|---|---|---|
| Revenue | | | |
| Chambers | $ 54.8 | $ 52.7 | $ 58.1 |
| Selkirk | 41.6 | 50.5 | 48.7 |
| Other | 89.7 | 101.2 | 109.8 |
| | 186.1 | 204.4 | 216.6 |
| Project expenses | | | |
| Chambers | 44.8 | 40.6 | 39.1 |
| Selkirk | 44.1 | 40.3 | 42.4 |
| Other | 61.8 | 88.9 | 92.7 |
| | 150.7 | 169.8 | 174.2 |
| Project other income (expense) | | | |
| Chambers | (3.0) | (2.5) | (1.9) |
| Selkirk | (0.7) | (1.5) | 1.3 |
| Other | (5.9) | (3.7) | (26.6) |
| | (9.6) | (7.7) | (27.2) |
| Project income (loss) | | | |
| Chambers | $ 7.0 | $ 9.6 | $ 17.1 |
| Selkirk | (3.2) | 8.7 | 7.6 |
| Other | 22.0 | 8.6 | (9.5) |
| | 25.8 | 26.9 | 15.2 |

**6. Inventory**

Inventory consists of the following:

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| Parts and other consumables | $ 11.8 | $ 11.3 |
| Fuel | 7.5 | 4.7 |
| Total inventory | $ 19.3 | $ 16.0 |

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**7. Property, plant and equipment**

| | December 31, 2014 | December 31, 2013 | Depreciable Lives |
|---|---|---|---|
| Land | $ 5.7 | $ 5.9 | |
| Office equipment, machinery and other | 4.7 | 3.3 | 3 - 10 years |
| Leasehold improvements | 0.5 | 0.4 | 7 - 15 years |
| Asset retirement obligation | 32.8 | 34.8 | 1 - 42 years |
| Plant in service | 1,914.9 | 1,938.4 | 1 - 45 years |
| Construction in progress | | 5.7 | |
| | 1,958.6 | 1,988.5 | |
| Less accumulated depreciation | (285.2) | (175.1) | |
| | $ 1,673.4 | $ 1,813.4 | |

Depreciation expense of $104.4 million, $106.0 million and $58.6 million was recorded for the years ended December 31, 2014, 2013 and 2012, respectively.

**8. Goodwill**

Our goodwill balance was $197.2 million and $296.3 million as of December 31, 2014 and December 31, 2013, respectively. We recorded $331.1 million of goodwill in connection with the acquisition of Capital Power Income L.P. (the "Partnership") in 2011. We apply an accounting standard under which goodwill has an indefinite life and is not amortized. Goodwill is tested for impairments at least annually, or more frequently whenever an event or change in circumstances occurs that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We test goodwill for impairment at the reporting unit level, which is at the project level and, the lowest level below the operating segments for which discrete financial information is available.

During the second quarter, based on the continued deficit of our market capitalization as compared to our book carrying value, we determined that it was appropriate to initiate an event-driven test of the remaining goodwill at our reporting units. The test was performed as of August 31, 2014 and concluded during the third quarter of 2014.

As a result of the event-driven goodwill assessment, we recorded a $17.9 million full impairment at the Kenilworth reporting unit (East segment), a $50.2 million full impairment at the Manchief reporting unit (West Segment) and a $23.7 million partial impairment at the Williams Lake reporting unit (West segment). The total impairment recorded in the three months ended September 30, 2014 was $91.8 million. The goodwill impairment recorded at each reporting unit was primarily due to (i) decreases in forward merchant energy prices subsequent to the expiration of the reporting units' respective energy service agreement ("ESA") or PPA, as applicable, as compared to the assumptions at the time of the reporting units' acquisition in November 2011, (ii) the continued amortization of cash flows under the reporting units' respective ESA or PPAs and (iii) an increase in the discount rate reflecting increased re-contracting risk. At the time of its acquisition in November 2011, the fair value of the assets acquired and liabilities assumed for each of the Kenilworth, Manchief and Williams Lake reporting units were valued assuming a merchant basis for the period subsequent to the expiration of the projects' original ESAs or PPAs. As discussed above, these forecasted energy revenues on a

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**8. Goodwill (Continued)**

merchant basis were higher than the energy prices currently forecasted to be in effect subsequent to the expiration of these reporting units' ESAs or PPAs. Power prices have declined from 2011 due to several factors including decreased demand and lower natural gas and oil prices resulting from an abundance of shale gas. Our forecasts for discounted cash flows also reflect a higher level of uncertainty for re-contracting at prices that were previously forecasted in 2011.

In addition, in the fourth quarter of 2014, we performed our annual goodwill impairment test as of November 30, 2014. Of the nine remaining reporting units with goodwill recorded, only Williams Lake failed step 1 of the two-step test. However, no impairment was recorded because the implied fair value of its goodwill exceeded the carrying value of its goodwill. Under step 1 of our goodwill impairment tests, the total fair value of the Curtis Palmer, Morris, Mamquam, Nipigon, North Bay, Kapuskasing, Calstock and Moresby Lake reporting units exceeded their carrying value by approximately $138 million or 25%.

Under our accounting policies for long-lived assets and goodwill impairment, we also perform an impairment analysis at the earlier of (i) executing a new PPA (or other arrangement) and (ii) six months prior to the expiration of an existing PPA. The Tunis project's PPA expired on December 31, 2014 and accordingly, we performed a long-lived asset impairment test and a goodwill impairment test as of June 30, 2014. Based on the results of our long-lived asset impairment test, it was determined that the weighted average estimated undiscounted cash flows for Tunis over its remaining useful life did not exceed the carrying value of the property, plant and equipment at the Tunis reporting unit. As a result, the project recorded a $9.6 million long-lived asset impairment charge in the three months ended June 30, 2014 which was the difference between the carrying value of the project's property, plant and equipment and its estimated fair market value.

Subsequent to adjusting the carrying value of the Tunis reporting unit for the $9.6 million long-lived asset impairment, we performed an impairment analysis for the project's goodwill. The project failed step 1 of the impairment test because the weighted average estimated discounted cash flows over its remaining useful life did not exceed the carrying value of the Tunis reporting unit. We performed step 2 of the goodwill impairment test and impaired all of the project's goodwill because the carrying value of goodwill exceeded its implied fair value. As a result, Tunis, a component of the East segment, recorded a $5.2 million goodwill impairment charge in the three months ended June 30, 2014. The implied fair value of goodwill was 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 were the purchase price. The total $14.8 million long-lived asset and goodwill impairment was primarily due to our assessment of the forecasted cash flows from re-contracting and other strategic outcomes.

We updated our probability-based long-lived asset impairment analysis for Tunis as of September 30, 2014 and December 31, 2014 and determined that, based on the weighted average estimated undiscounted cash flows for the project over its remaining useful life, no further impairment of long-lived assets was required.

We determine the fair value of our reporting units using an income approach with discounted cash flow ("DCF") models, as we believe forecasted cash flows are the best indicator of such fair value. A number of significant assumptions and estimates are involved in the application of the DCF model to forecast operating cash flows, including assumptions about discount rates, projected merchant power

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**8. Goodwill (Continued)**

prices, generation, fuel costs and capital expenditure requirements. The undiscounted and discounted cash flows utilized in our long-lived asset recovery and step 1 and 2 goodwill impairment tests for our reporting units are generally based on approved reporting unit operating plans for years with contracted PPAs and historical relationships for estimates at the expiration of PPAs. All cash flow forecasts from DCF models utilized estimated plant output for determining assumptions around future generation and industry data forward power and fuel curves to estimate future power and fuel prices. We used historical experience to determine estimated future capital investment requirements. The discount rate applied to the DCF models represents the weighted average cost of capital ("WACC") consistent with the risk inherent in future cash flows of the particular reporting unit and is based upon an assumed capital structure, cost of long-term debt and cost of equity consistent with comparable independent power producers. The betas used in calculating the WACC rate were obtained from reputable third party sources. We utilized the assistance of valuation experts to perform step 1 and step 2 of the quantitative impairment test for several of our reporting units. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of goodwill.

The valuation of long-lived assets and goodwill for the impairment analyses is considered a level 3 fair value measurement, which means that the valuation of the assets and liabilities reflect management's own judgments regarding the assumptions market participants would use in determining the fair value of the assets and liabilities. Fair value determinations require considerable judgment and are sensitive to changes in these underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of a goodwill impairment test will prove to be accurate predictions of the future. Examples of events or circumstances that could reasonably be expected to negatively affect the underlying key assumptions and ultimately impact the estimated fair value of our reporting units may include macroeconomic factors that significantly differ from our assumptions in timing or degree, increased input costs such as higher fuel prices and maintenance costs, or lower power prices than incorporated in our long-term forecasts.

The following table is a rollforward of goodwill for the year ended December 31, 2014:

| | East | West | Wind | Un-allocated corporate | Total |
|---|---|---|---|---|---|
| Balance at December 31, 2012 | $ 138.6 | $ 192.6 | $ | $ | $ 331.2 |
| Impairment of goodwill | (30.8) | (4.1) | | | (34.9) |
| Balance at December 31, 2013 | 107.8 | 188.5 | | | 296.3 |
| Impairment of goodwill | (23.1) | (73.9) | | | (97.0) |
| Translation adjustment | | (2.1) | | | (2.1) |
| Balance at December 31, 2014 | $ 84.7 | $ 112.5 | $ | $ | $ 197.2 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**9. Power purchase agreements and other intangible assets and liabilities**

Other intangible assets and liabilities include power purchase agreements, fuel supply agreements and capitalized development costs. The following tables summarize the components of our intangible assets and other liabilities subject to amortization for the years ended December 31, 2014 and 2013:

| | Other Intangible Assets, Net | | |
|---|---|---|---|
| | Power Purchase Agreements | Development Costs | Total |
| Gross balances, December 31, 2014 | $ 576.9 | $ 4.8 | $ 581.7 |
| Less: accumulated amortization | (199.8) | (0.5) | (200.3) |
| Net carrying amount, December 31, 2014 | $ 377.1 | $ 4.3 | $ 381.4 |

| | Other Intangible Assets, Net | | |
|---|---|---|---|
| | Power Purchase Agreements | Development Costs | Total |
| Gross balances, December 31, 2013 | $ 598.5 | $ 4.8 | $ 603.3 |
| Less: accumulated amortization | (151.5) | (0.3) | (151.8) |
| Net carrying amount, December 31, 2013 | $ 447.0 | $ 4.5 | $ 451.5 |

| | Power Purchase and Fuel Supply Agreement Liabilities, Net | | |
|---|---|---|---|
| | Power Purchase Agreements | Fuel Supply Agreements | Total |
| Gross balances, December 31, 2014 | $ (32.2) | $ (12.6) | $ (44.8) |
| Less: accumulated amortization | 7.7 | 3.7 | 11.4 |
| Net carrying amount, December 31, 2014 | $ (24.5) | $ (8.9) | $ (33.4) |

| | Power Purchase and Fuel Supply Agreement Liabilities, Net | | |
|---|---|---|---|
| | | | Total |

| | Power Purchase Agreements | Fuel Supply Agreements | |
|---|---|---|---|
| Gross balances, December 31, 2013 | $ (34.1) | $ (12.6) | $ (46.7) |
| Less: accumulated amortization | 5.5 | 2.5 | 8.0 |
| Net carrying amount, December 31, 2013 | $ (28.6) | $ (10.1) | $ (38.7) |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**9. Power purchase agreements and other intangible assets and liabilities (Continued)**

The following table presents amortization expense of intangible assets for the years ended December 31, 2014, 2013 and 2012:

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| Power purchase agreements | $ 57.9 | $ 60.8 | $ 59.5 |
| Fuel supply agreements | (1.2) | (1.2) | (1.2) |
| Total amortization | $ 56.7 | $ 59.6 | $ 58.3 |

The following table presents estimated future amortization expense for the next five years related to power purchase agreements and fuel supply agreements:

| Year Ended December 31, | Power Purchase Agreements | Fuel Supply Agreements |
|---|---|---|
| 2015 | $ 55.0 | $ (1.2) |
| 2016 | 55.0 | (1.2) |
| 2017 | 55.1 | (1.2) |
| 2018 | 47.3 | (1.2) |
| 2019 | 45.0 | (1.2) |

The following table presents the weighted average remaining amortization period related to our intangible assets as of December 31, 2014:

| As of December 31, 2014 | Power Purchase Agreements | Fuel Supply Agreements |
|---|---|---|
| **(in years)** | | |
| Weighted average remaining amortization period | 8.6 | 8.6 |

**10. Other long-term liabilities**

Other long-term liabilities consist of the following:

| | 2014 | 2013 |
|---|---|---|
| Asset retirement obligations | $ 55.2 | $ 57.7 |
| Net pension liability | 3.1 | 0.8 |
| Deferred revenue | 0.9 | 4.0 |
| Accrued LTIP and director share units | 1.1 | 0.6 |
| Other | 3.9 | 2.3 |
| | $ 64.2 | $ 65.4 |

We assumed asset retirement obligations ("AROs") in our acquisition of the Partnership. During 2012, we also recorded AROs related to the Canadian Hills project. We recorded these AROs as we are legally required to remove these facilities at the end of their useful lives and restore the sites to their original condition. The following table represents the fair value of AROs at the date of

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**10. Other long-term liabilities (Continued)**

acquisition along with the additions, reductions and accretion related to our ARO for the year ended December 31, 2014:

| | 2014 |
|---|---|
| Asset retirement obligations beginning of year | $ 57.7 |
| Accretion of asset retirement obligations | 1.5 |
| Sale of Greeley | (2.0) |
| Translation adjustments | (2.0) |
| Asset retirement obligations, end of year | $ 55.2 |

**11. Long-term debt**

Long-term debt consists of the following:

| | December 31, 2014 | December 31, 2013 | Interest Rate |
|---|---|---|---|
| **Recourse Debt:** | | | |
| Senior secured term loan facility, due 2021 | $ 541.5 | $ | LIBOR[1] plus 3.8% |
| Senior unsecured notes, due 2018[2] | 319.9 | 460.0 | 9.0% |
| Senior unsecured notes, due June 2036 (Cdn$210.0) | 181.0 | 197.4 | 6.0% |
| Senior unsecured notes, due July 2014[3] | | 190.0 | 5.9% |
| Series A senior unsecured notes, due August 2015[3] | | 150.0 | 5.9% |
| Series B senior unsecured notes, due August 2017[3] | | 75.0 | 6.0% |
| **Non-Recourse Debt:** | | | |
| Epsilon Power Partners term facility, due 2019 | 25.5 | 30.5 | LIBOR plus 3.1% |
| Cadillac term loan, due 2025 | 33.4 | 35.4 | 6.0% - 8.0% |
| Piedmont term loan, due 2018[4] | 64.0 | 76.6 | 5.2% |
| Meadow Creek term loan, due 2024 | 164.9 | 169.8 | 2.9% - 5.6% |
| Rockland term loan, due 2027 | 83.8 | 85.3 | 6.4% |
| Other long-term debt | 0.7 | 1.0 | 5.5% - 6.7% |
| Less: current maturities | (26.4) | (216.2) | |
| Total long-term debt | $ 1,388.3 | $ 1,254.8 | |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**11. Long-term debt (Continued)**

Current maturities consist of the following:

| | December 31, 2014 | December 31, 2013 | Interest Rate |
|---|---|---|---|
| **Current Maturities:** | | | |
| Senior secured term loan facility, due 2021 | $ 5.4 | $ | LIBOR[1] plus 3.8% |
| Senior unsecured notes, due July 2014[3] | | 190.0 | 5.9% |
| Epsilon Power Partners term facility, due 2019 | 6.1 | 5.0 | LIBOR plus 3.1% |
| Cadillac term loan, due 2025 | 3.9 | 2.0 | 6.0% - 8.0% |
| Piedmont term loan, due 2018[4] | 4.5 | 12.6 | 5.2% |
| Meadow Creek term loan, due 2024 | 4.6 | 4.9 | 2.9% - 5.6% |
| Rockland term loan, due 2027 | 1.8 | 1.5 | 6.4% |
| Other short-term debt | 0.1 | 0.2 | 5.5 - 6.7% |
| Total current maturities | $ 26.4 | $ 216.2 | |

(1) LIBOR cannot be less than 1.00%. On May 5, 2014 we entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $199.0 million notional amount ($182.7 million at December 31, 2014) of the $600.0 million ($541.5 million at December 31, 2014) outstanding aggregate borrowings under our senior secured term loan facility. See Note 14, *Accounting for derivative instruments and hedging activities* for further details.

(2) We repurchased approximately $140.1 million aggregate principal amount of the 9.0% Notes in March 2014 with a portion of the proceeds from the Senior Secured Credit Facilities and cash on hand, as further described below. We also repurchased $9.0 million aggregate principal in January 2015 with cash on hand.

(3) The Curtis Palmer Notes, Series A Notes and Series B Notes were retired on February 26, 2014 with proceeds from the Senior Secured Credit Facilities, as further described below.

(4) On February 14, 2014, we paid down $8.1 million of principal on the Piedmont construction loan and converted the remaining $68.5 million to a term loan due August 2018.

Principal payments on the maturities of our debt due in the next five years and thereafter are as follows:

| | |
|---|---|
| 2015 | $ 26.4 |
| 2016 | 24.4 |
| 2017 | 26.9 |
| 2018 | 394.8 |
| 2019 | 18.8 |
| Thereafter | 923.4 |
| | $ 1,414.7 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**11. Long-term debt (Continued)**

***Senior Secured Credit Facilities***

On February 24, 2014, Atlantic Power Limited Partnership ("the Partnership"), our wholly-owned indirect subsidiary, entered into a new senior secured term loan facility (the "Term Loan Facility"), comprising of $600 million in aggregate principal amount, and a new senior secured revolving credit facility (the "Revolving Credit Facility") with a capacity of $210 million (collectively, the "Senior Secured Credit Facilities"). Borrowings under the Senior Secured Credit Facilities are available in U.S. dollars and Canadian dollars and bear interest at a rate equal to the Adjusted Eurodollar Rate (LIBOR), the Base Rate or the Canadian Prime Rate, each as defined in the credit agreement governing the Senior Secured Credit Facilities (the "Credit Agreement"), as applicable, plus an applicable margin between 2.75% and 3.75% that varies depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. The applicable margin for term loans bearing interest at the Adjusted Eurodollar Rate and the Base Rate is 3.75% and 2.75% respectively and was 3.75% at December 31, 2014. The Adjusted Eurodollar Rate cannot be less than 1.00% (1.00% at December 31, 2014). As further described in Note 14, the Partnership entered into interest rate swap agreements on May 5, 2014 to mitigate the exposure to changes in the Adjusted Eurodollar Rate for a portion of the Term Loan Facility.

In connection with the funding of the Senior Secured Credit Facilities, we terminated our prior revolving credit facility on February 26, 2014.

The Term Loan Facility matures on February 24, 2021. The revolving commitments under the Revolving Credit Facility terminate on February 24, 2018. Letters of credit are available to be issued under the revolving commitments until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. The Partnership is required to pay a commitment fee with respect to the commitments under the Revolving Credit Facility equal to 0.75% times the average of the daily difference between the revolving commitments and all outstanding revolving loans (excluding swing line loans) plus amounts available to be drawn under letters of credit and all outstanding reimbursement obligations with respect to drawn letters of credit.

The Senior Secured Credit Facilities are secured by a pledge of the equity interests in the Partnership and its subsidiaries, guaranties from the Partnership subsidiary guarantors and a limited recourse guaranty from the entity that holds all of the Partnership equity, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of the Partnership and its subsidiaries (subject to certain exceptions), and certain other assets. The Senior Secured Credit Facilities are not otherwise guaranteed or secured by us or any of our subsidiaries (other than the Partnership subsidiary guarantors). The Senior Secured Credit Facilities have a debt service reserve account, which is required to be funded and maintained at the debt service reserve requirement, equal to six months of debt service. The debt service reserve requirement was funded with a $15.8 million letter of credit.

The Partnership's existing Cdn$210 million aggregate principal amount of 5.95% Medium Term Notes due June 23, 2036 (the "MTNs") prohibit the Partnership (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries) to secure indebtedness, unless the MTNs are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, the Partnership has granted an equal and ratable security

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**11. Long-term debt (Continued)**

interest in the collateral package securing the Senior Secured Credit Facilities under the indenture governing the MTNs for the benefit of the holders of the MTNs.

The Credit Agreement contains customary representations, warranties, terms and conditions, and covenants. The covenants include a requirement that the Partnership and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 5.25:1.00 in 2014 to 4.00:1.00 in 2021, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 2.50:1.00 in 2014 to 3.25:1.00 in 2021. In addition, the Credit Agreement includes customary restrictions and limitations on the Partnership's and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v) modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case subject to customary carve-outs and exceptions and various thresholds.

Under the Credit Agreement, if a change of control (as defined in the Credit Agreement) occurs, unless the Partnership elects to make a voluntary prepayment of the term loans under the Senior Secured Credit Facilities, it will be required to offer each electing lender to prepay such lender's term loans under the Senior Secured Credit Facilities at a price equal to 101% of par. In addition, in the event that the Partnership elects to repay, prepay or refinance all or any portion of the term loan facilities within one year from the initial funding date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid or refinanced.

The Credit Agreement also contains a mandatory amortization feature and customary mandatory prepayment provisions, including: (i) from proceeds of assets sales, insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and (ii) the payment of 50% of the excess cash flow, as defined in the Credit Agreement, of the Partnership and its subsidiaries.

Under certain conditions the lending commitments under the Credit Agreement may be terminated by the lenders and amounts outstanding under the Credit Agreement may be accelerated. Such events of default include failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations or warranties in any material respect, non-payment or acceleration of other material debt of the Partnership and its subsidiaries, bankruptcy, material judgments rendered against the Partnership or certain of its subsidiaries, certain ERISA or regulatory events, a change of control of the Partnership, or defaults under certain guaranties and collateral documents securing the Senior Secured Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

On February 26, 2014, $600 million was drawn under the Term Loan Facility, and letters of credit in an aggregate face amount of $144.1 million ($105.7 million as of December 31, 2014) were issued (but not drawn) pursuant to the revolving commitments under the Revolving Credit Facility and used to (i) satisfy a debt service reserve requirement in an amount equivalent to six months of debt service (approximately $15.8 million) and (ii) support contractual credit support obligations of the Partnership and its subsidiaries and of certain other of our affiliates.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**11. Long-term debt (Continued)**

We and our subsidiaries have used the proceeds from the Term Loan Facility under the Senior Secured Credit Facilities to:

- redeem in whole, at a price equal to par plus $31.1 million of accrued interest and make-whole premiums (i) the $150 million aggregate principal amount outstanding of 5.87% Senior Guaranteed Notes, Series A, due 2015 (the "Series A Notes") and the $75 million aggregate principal amount outstanding of 5.97% Senior Guaranteed Notes, Series B, due 2017 (the "Series B Notes") issued by Atlantic Power (US) GP, and (ii) the $190 million aggregate principal amount outstanding of 5.9% Senior Notes due 2014 issued by Curtis Palmer LLC (the "Curtis Palmer Notes");

- pay transaction costs and expenses of approximately $40.0 million including banking, legal and consulting fees which were capitalized as deferred financing costs; and

- make a distribution to us in the amount of $122 million which was used, in addition to cash on hand, to repurchase $140.1 million aggregate principal amount of the 9.0% Notes (as defined below) of Atlantic Power Corporation, make $15.7 million in accrued interest and premium payments as part of the aggregate repurchase price, and $0.1 million in commission fees associated with the repurchases.

In connection with the termination of our prior credit facility, we terminated the interest rate swap at Epsilon Power Partners, a wholly owned subsidiary, a portion of our natural gas swaps at Orlando and foreign exchange forward contracts at the Partnership. As a result of the termination of these contracts, we recorded $2.6 million of interest expense, $4.0 million of fuel expense and $0.4 million of foreign exchange loss, respectively.

The prior credit facility contained certain guaranties, which were terminated in connection with the termination of the prior credit facility. In addition, the terms of the 9.0% Notes provide that the guarantors of the prior credit facility guarantee the 9.0% Notes. As a result, upon termination of our prior credit facility and its related guaranties, the guaranties under the 9.0% Notes were cancelled and the guarantors of the 9.0% Notes were automatically released from all of their obligations under such guaranties.

***Notes of Atlantic Power Corporation***

On November 5, 2011, we completed a private placement of $460.0 million aggregate principal amount of 9.0% senior notes due 2018 (the "9.0% Notes") to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933, as amended (the "Securities Act"), and to non-U.S. persons outside of the United States in compliance with Regulation S under the Securities Act. The 9.0% Notes were issued at an issue price of 97.471% of the face amount of the 9.0% Notes for aggregate gross proceeds to us of $448.0 million.

On March 25, 2014, we agreed, in privately-negotiated transactions, to repurchase approximately $140.1 million aggregate principal amount of the 9.0% Notes from certain holders. We paid $15.7 million in accrued interest and premiums as part of the aggregate repurchase price, paid $0.1 million in commission fees associated with the repurchases, and wrote off $5.3 million of deferred financing costs related to the repurchase. The premiums, accrued interest and write-off of deferred

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**11. Long-term debt (Continued)**

financing costs were recorded to interest expense. We also repurchased $9.0 million aggregate principal amount of the 9.0% Notes in January 2015 with cash on hand.

As previously disclosed with respect to the impact of the Senior Secured Credit Facilities in our Annual Report on Form 10-K for the year ended December 31, 2013, due to the aggregate impact of the up-front costs resulting from the prepayments on our indebtedness described above, including the premium payment and charges for unamortized debt discount and fee expenses and premiums as part of the overall purchase price in respect of the repurchases of the 9.0% Notes (all such up-front costs, collectively, the "Prepayment Charges"), which were reflected as interest expense in our 2014 first quarter results, we no longer satisfy the fixed charge coverage ratio test included in the restricted payments covenant of the indenture governing the 9.0% Notes. The fixed charge coverage ratio must be at least 1.75 to 1.00 and is measured on a rolling four quarter basis, including after giving effect to certain pro forma adjustments.

As a consequence, further dividend payments, which are declared and paid at the discretion of our board of directors, in the aggregate cannot exceed the covenant's "basket" provision of the greater of $50 million and 2% of consolidated net assets (approximately $55.8 million at December 31, 2014) until such time that we satisfy the fixed charge coverage ratio test. We have declared dividends in 2014, totaling approximately $32.5 million that were subject to the basket provision. For the trailing twelve months ended December 31, 2014, dividend payments to our shareholders totaled approximately Cdn$46.7 million. In September 2014, we adjusted our dividend to Cdn$0.03 per common share to be paid quarterly based on an annual dividend payment of Cdn$0.12 per common share, with the first quarterly dividend declared in November and paid at the end of December 2014. No dividends were declared in September 2014. Dividends to shareholders are paid, if and when declared by, and subject to the discretion of, the Board of Directors.

The Prepayment Charges would no longer be reflected in the calculation of the fixed charge coverage ratio test after the passage of four additional successive quarters following the quarter in which the Prepayment Charges are incurred. In addition, any similar prepayment charges incurred in connection with any further debt reduction would also be reflected in the calculation of the fixed charge coverage ratio test on a rolling four quarter basis, beginning with the quarter in which such charges are incurred, as would any associated reduction in interest expense.

The 9.0% Notes are subject to redemption, at the option of Atlantic Power, in whole or in part, at any time on or after November 15, 2014, upon not less than 30 nor more than 60 days' notice, at the following redemption prices (expressed as a percentage of principal amount of the 9.0% Notes to be redeemed) (November 15, 2014 104.5%, November 15, 2015 102.25%, November 15, 2016 and thereafter 100%), plus accrued and unpaid interest.

***Notes of the Partnership***

The Partnership, a wholly-owned subsidiary acquired on November 5, 2011, has outstanding Cdn$210.0 million ($181.0 million as of December 31, 2014) aggregate principal amount of 5.95% senior unsecured notes, due June 2036 (MTNs). Interest on the MTNs is payable semi-annually at 5.95%. Pursuant to the terms of the MTNs, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. The MTNs are guaranteed by Atlantic Power Corporation and Atlantic Power Preferred Equity Ltd., an indirect, wholly-owned subsidiary acquired in connection with the acquisition of the Partnership.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**11. Long-term debt (Continued)**

***Non-Recourse Debt***

Project-level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The loans have certain financial covenants that must be met in order to distribute available cash. At December 31, 2014, all of our projects with the exception of Piedmont were in compliance with the covenants contained in project-level debt. We do not expect our Piedmont project to meet its debt service coverage ratio covenants or to make distributions before 2017 at the earliest, due to continued operational issues that have resulted in higher forecasted maintenance and fuel expenses than initially expected.

**12. Convertible debentures**

The following table provides details related to outstanding convertible debentures:

| | 6.5% Debentures due October 2014 | 6.25% Debentures due March 2017 | 5.6% Debentures due June 2017 | 5.75% Debentures due June 2019 | 6.00% Debentures due December 2019 | Total |
|---|---|---|---|---|---|---|
| Balance at December 31, 2012 | $ 45.1 | $ 67.8 | $ 81.0 | $ 130.0 | $ 100.3 | $ 424.2 |
| Foreign exchange gain | (3.0) | (4.4) | (5.3) | | (6.3) | (19.0) |
| Balance at December 31, 2013 | $ 42.1 | $ 63.4 | $ 75.7 | $ 130.0 | $ 94.0 | $ 405.2 |
| Repayment of convertible debentures | (40.7) | | (0.7) | (1.3) | (0.4) | (43.1) |
| Foreign exchange (gain) loss | (1.4) | (5.3) | (6.4) | | (7.7) | (20.8) |
| Gain on repurchase of convertible debentures | | (0.1) | | (0.4) | (0.2) | (0.7) |
| Balance at December 31, 2014 | $ | $ 58.0 | $ 68.6 | $ 128.3 | $ 85.7 | $ 340.6 |

Aggregate interest expense related to the convertible debentures was $22.8 million, $24.2 million, and $12.1 million for the years ended December 31, 2014, 2013, and 2012, respectively.

In 2006 we issued, in a public offering, Cdn$60 million aggregate principal amount of 6.25% convertible secured debentures (the "2006 Debentures") for gross proceeds of $52.8 million. The 2006 Debentures paid interest semi-annually on April 30 and October 31 of each year, had an initial maturity date of October 31, 2011 and were convertible into approximately 80.6452 common shares per Cdn$1,000 principal amount of 2006 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per common share. The 2006 Debentures were secured by a subordinated pledge of our interest in certain subsidiaries and contain certain restrictive covenants. In connection with our conversion to a common share structure on November 27, 2009, the holders of the 2006 Debentures approved an amendment to increase the annual interest rate from 6.25% to 6.50% and separately, an extension of the maturity date from October 2011 to October 2014. Over the maturity term of the 2006 Debentures, Cdn$15.2 million of the 2006 Debentures were converted to 1.2 million common shares. On October 31, 2014, we used Cdn$44.8 million of cash on hand to repay the 2006 Debentures at maturity.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**12. Convertible debentures (Continued)**

On December 17, 2009, we issued, in a public offering, Cdn$86.3 million aggregate principal amount of 6.25% convertible unsecured debentures (the "2009 Debentures") for gross proceeds of $82.1 million. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share. As of December 31, 2014, a cumulative Cdn$18.8 million of the 2009 Debentures, have been converted to 1.4 million common shares.

On October 20, 2010, we issued, in a public offering, Cdn$80.5 million aggregate principal amount of 5.60% convertible unsecured subordinated debentures (the "2010 Debentures") for gross proceeds of $78.9 million. The 2010 Debentures pay interest semi-annually on June 30 and December 30 of each year. The 2010 Debentures mature on June 30, 2017, unless earlier redeemed. The debentures are convertible into our common shares at an initial conversion rate of 55.2486 common shares per Cdn$1,000 principal amount of 2010 Debentures, at any time, at the option of the holder, representing an initial conversion price of approximately Cdn$18.10 per common share.

On July 5, 2012, we issued, in a public offering, $130.0 million aggregate principal amount of 5.75% convertible unsecured subordinated debentures due June 30, 2019 (the "July 2012 Debentures") for net proceeds of $124.0 million. The July 2012 Debentures pay interest semi-annually on the last day of June and December of each year. The July 2012 Debentures are convertible into our common shares at an initial conversion rate of 57.9710 common shares per $1,000 principal amount of July 2012 debentures representing a conversion price of $17.25 per common share. We used the proceeds to fund a portion of our equity commitment in Canadian Hills.

On December 11, 2012, we issued, in a public offering, Cdn$100 million aggregate principal amount of 6.00% convertible unsecured subordinated debentures due December 31, 2019 (the "December 2012 Debentures") for net proceeds of Cdn$95.5 million. The December 2012 Debentures pay interest semi-annually on the last day of June and December of each year beginning June 30, 2013. The December 2012 Debentures are convertible into our common shares at an initial conversion rate of 68.9655 common shares per Cdn$1,000 principal amount of December 2012 Debentures representing a conversion price of Cdn$14.50 per common share. We used the proceeds to acquire all of the outstanding shares of capital stock of Ridgeline and to fund certain working capital commitments and acquisition expenses related to Ridgeline.

During the fourth quarter of 2014, we announced a Normal Course Issuer Bid ("NCIB") for our convertible debentures. Under the NCIB, we entered into a pre-defined automatic securities purchase plan with our broker in order to facilitate purchases of our convertible debentures. The NCIB commenced on November 11, 2014 and will expire on November 10, 2015 or such earlier date as we complete our purchases pursuant to the NCIB. The actual amount of convertible debentures that may be purchased under the NCIB cannot exceed approximately $31 million and is further limited based on the outstanding principal of the individual outstanding tranches. As of December 31, 2014 we had repurchased and cancelled $3.1 million of convertible debentures and recorded a gain of $0.7 million in the consolidated statement of operations related to these transactions.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**13. Fair value of financial instruments**

The estimated carrying values and fair values of our recorded financial instruments related to operations are as follows:

| | December 31, | | | |
|---|---|---|---|---|
| | 2014 | | 2013 | |
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash and cash equivalents | $ 109.9 | $ 109.9 | $ 158.6 | $ 158.6 |
| Restricted cash | 41.6 | 41.6 | 114.2 | 114.2 |
| Derivative assets current | | | 0.2 | 0.2 |
| Derivative assets non-current | 1.1 | 1.1 | 13.0 | 13.0 |
| Derivative liabilities current | 39.2 | 39.2 | 28.5 | 28.5 |
| Derivative liabilities non-current | 57.5 | 57.5 | 76.1 | 76.1 |
| Long-term debt, including current portion | 1,414.7 | 1,345.2 | 1,471.0 | 1,435.2 |
| Convertible debentures | 340.6 | 269.9 | 405.2 | 281.1 |

Our financial instruments that are recorded at fair value have been classified into levels using a fair value hierarchy.

The three levels of the fair value hierarchy are defined below:

Level 1 Unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date. Financial assets utilizing Level 1 inputs include active exchange-traded securities.

Level 2 Quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.

Level 3 Unobservable inputs from objective sources. These inputs may be based on entity-specific inputs. Level 3 inputs include all inputs that do not meet the requirements of Level 1 or Level 2.

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of December 31, 2014 and December 31, 2013.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**13. Fair value of financial instruments (Continued)**

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

| | December 31, 2014 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Assets: | | | | |
| Cash and cash equivalents | $ 109.9 | $ | $ | $ 109.9 |
| Restricted cash | 41.6 | | | 41.6 |
| Derivative instruments asset | | 1.1 | | 1.1 |
| Total | $ 151.5 | $ 1.1 | $ | $ 152.6 |
| Liabilities: | | | | |
| Derivative instruments liability | $ | $ 96.7 | $ | $ 96.7 |
| Total | $ | $ 96.7 | $ | $ 96.7 |

| | December 31, 2013 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Assets: | | | | |
| Cash and cash equivalents | $ 158.6 | $ | $ | $ 158.6 |
| Restricted cash | 114.2 | | | 114.2 |
| Derivative instruments asset | | 13.2 | | 13.2 |
| Total | $ 272.8 | $ 13.2 | $ | $ 286.0 |
| Liabilities: | | | | |
| Derivative instruments liability | $ | $ 104.6 | $ | $ 104.6 |
| Total | $ | $ 104.6 | $ | $ 104.6 |

The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment. The fair values of such financial instruments are classified within Level 2 of the fair value hierarchy. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk free interest rate.

We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. As of December 31, 2014, the credit valuation adjustments resulted in a $13.0 million net increase in fair value, which consists of a $0.7 million pre-tax gain in other comprehensive income and a $12.3 million gain in change in fair value of derivative instruments. As of December 31, 2013, the credit valuation adjustments resulted in an $11.1 million net increase in fair value, which consists of a $0.5 million pre-tax gain in other comprehensive income and a $10.6 million gain in change in fair value of derivative instruments.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**13. Fair value of financial instruments (Continued)**

The carrying amounts for cash and cash equivalents and restricted cash approximate fair value due to their short-term nature. The fair value of long-term debt and convertible debentures was determined using quoted market prices, as well as discounting the remaining contractual cash flows using a rate at which we could issue debt with a similar maturity as of the balance sheet date.

**14. Accounting for derivative instruments and hedging activities**

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. We have one contract designated as a cash flow hedge, and we defer the effective portion of the change in fair value of the derivatives in accumulated other comprehensive income (loss), until the hedged transactions occur and are recognized in earnings (loss). The ineffective portion of a cash flow hedge is immediately recognized in earnings (loss). For our other derivatives that are not designated as cash flow hedges, the changes in the fair value are immediately recognized in earnings (loss). These guidelines apply to our natural gas swaps, interest rate swaps, and foreign exchange contracts.

*Gas purchase agreements*

Gas purchase agreements to purchase gas forward at our North Bay, Kapuskasing and Nipigon projects do not qualify for the normal purchase normal sales ("NPNS") exemption and are accounted for as derivative financial instruments. The gas purchase agreements at North Bay and Kapuskasing satisfy all of the forecasted fuel requirements for these projects through their expiration on December 31, 2016. The gas purchase agreement for Nipigon satisfies the majority of forecasted fuel requirements through December 31, 2022. These derivative financial instruments are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

In June 2014, the Partnership entered into contracts for the purchase of 2.9 million Gigajoules ("Gj") of future natural gas purchases beginning on November 1, 2014 and expiring on December 31, 2017 for our projects in Ontario. These contracts effectively fix the price of approximately 98% of our expected uncontracted gas requirements for each of 2014 and 2015 and 32% and 30% of our expected uncontracted gas requirements for 2016 and 2017, respectively. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2014. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

*Natural gas swaps*

Our strategy to mitigate future exposure to changes in natural gas prices at our projects consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. We previously entered into

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**14. Accounting for derivative instruments and hedging activities (Continued)**

natural gas swaps to effectively fix the price of 4.5 million Mmbtu of future natural gas purchases. On February 20, 2014, we paid $4.0 million to terminate a portion of these contracts in connection with the termination of our prior revolving credit facility. We recorded fuel expense related to the settlement of these contracts in the consolidated statement of operations.

We have entered into various natural gas swaps to effectively fix the price of 6.3 million Mmbtu of future natural gas purchases at Orlando, which is approximately 100% of our share of the expected on-peak natural gas purchases at the project through 2016 or approximately 63% of our share of the expected base load natural gas purchases for 2015 and 2016, respectively. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2014. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

*Interest rate swaps*

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.0% through February 15, 2015, 6.1% from February 16, 2015 to February 15, 2019, 6.3% from February 16, 2019 to February 15, 2023, and 6.4% thereafter. The notional amount of the interest rate swap agreement matches the outstanding principal balance over the remaining life of Cadillac's debt. This swap agreement, which qualifies for and is designated as a cash flow hedge, is effective through June 2025 and the effective portion of the changes in the fair market value is recorded in accumulated other comprehensive income (loss).

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converts the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.8% through February 29, 2016. From February 2016 until the maturity of the debt in November 2017, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.5%. The swap continues at the fixed rate of 4.47% from the maturity of the debt in November 2017 until November 2030. Prior to conversion of the Piedmont Construction loan facility to a term loan, the notional amounts of the interest rate swap agreements matched the estimated outstanding principal balance of Piedmont's construction loan facility. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively. As a result of the Piedmont term loan conversion on February 14, 2014, these swap agreements were amended to reduce the notional amounts to match the outstanding $68.5 million principal of the term loan. We recorded $1.0 million of deferred financing costs related to this transaction in the consolidated balance sheets. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

Rockland Wind Farm, LLC ("Rockland") entered into interest rate swaps to manage interest rate risk exposure. These swaps effectively modify the project's exposure by converting the project's floating rate debt to a fixed basis. The interest rate swaps are with various counterparties and swap 100% of the expected interest payments from floating LIBOR to fixed rates structured in two tranches. The first tranche is for the expected interest payments for the current period through December 31, 2026 and fixes the interest rate at 4.2% plus an applicable margin of 2.3% - 2.8%. The second tranche is for the

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**14. Accounting for derivative instruments and hedging activities (Continued)**

expected interest payments for the period beginning December 31, 2026 and ending December 31, 2031, fixing the interest rate at 7.8%. The interest rate swap agreements are not designated as a hedge and changes in their fair market value are recorded in the consolidated statements of operations.

The Meadow Creek project ("Meadow Creek") has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreements effectively convert 75% of the floating rate debt to a fixed interest rate of 2.3% plus an applicable margin of 2.8% - 3.3% through December 31, 2024. The second tranche is the post-term portion of the loan, or the balloon payment and commences on December 31, 2024 and ends on December 31, 2030, fixing the interest rate at 7.2%. The interest rate swaps were both executed on September 17, 2012 and expire on December 31, 2024 and December 31, 2030, respectively. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

Epsilon Power Partners, our wholly owned subsidiary, previously had an interest rate swap to economically fix the exposure to changes in interest rates related to the variable-rate non-recourse debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 7.37% and had a maturity date of July 2019. The notional amount of the swap matched the outstanding principal balance over the remaining life of Epsilon Power Partners' debt. On February 20, 2014, we paid $2.6 million to terminate this contract in connection with the termination of our prior revolving credit facility. We recorded interest expense related to its settlement in the consolidated statement of operations. This interest rate swap agreement was not designated as a hedge and changes in its fair market value were recorded in the consolidated statements of operations.

On May 5, 2014 the Partnership entered into interest rate swap agreements to mitigate exposure to changes in the Adjusted Eurodollar Rate for $199.0 million notional amount ($182.7 million at December 31, 2014) of the $600 million aggregate principal amount of borrowings ($541.5 million of borrowings at December 31, 2014) under the Term Loan Facility. Borrowings under the $600 million Term Loan Facility bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 3.75%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00% resulting in a minimum of a 4.75% all-in rate on the Term Loan Facility. As a result of entering into the swap agreements, the all-in rate for $199.0 million of the Term Loan Facility cannot be less than 4.91% if the Adjusted Eurodollar Rate is equal to or greater than 1.00%. If the Adjusted Eurodollar Rate is below 1.00%, we will pay interest at a rate equivalent to the minimum 4.75% all-in rate plus any difference between the actual Adjusted Eurodollar Rate and 1.16%. The interest rate swap agreements were effective June 30, 2014 and terminate on December 29, 2017. The interest rate swap agreements are not designated as hedges and changes in their fair market value will be recorded in the consolidated statements of operations.

*Foreign currency forward contracts*

From time to time, we use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as many of our projects generate cash flow in U.S. dollars and Canadian dollars. On February 20, 2014, we paid $0.4 million to terminate all of our remaining foreign currency forward contracts in connection with the termination of our prior revolving credit facility and recorded their settlement in foreign exchange gain in the consolidated statement of operations for the three

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**14. Accounting for derivative instruments and hedging activities (Continued)**

months ended March 31, 2014. On April 2, 2014, we executed a foreign currency forward contract in which we agreed to sell $41.0 million on September 30, 2014 and receive Cdn$45.3 million at a foreign exchange rate of Cdn$1.105 per U.S. dollar in order to mitigate the foreign exchange risk on the repayment at maturity of the Cdn$44.8 million convertible debentures due in October 2014. We recorded a $0.5 million realized foreign exchange loss on the expiration of the foreign currency forward contract on September 30, 2014. We repaid the Cdn$44.8 million convertible debentures with cash on hand at their maturity on October 31, 2014.

*Volume of forecasted transactions*

We have entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for the NPNS exemption as of year ended December 31, 2014 and December 31, 2013:

| | Units | December 31, 2014 | December 31, 2013 |
|---|---|---|---|
| Natural gas swaps | Natural Gas (Mmbtu) | 6.3 | 5.6 |
| Gas purchase agreements | Natural Gas (Gigajoules) | 33.9 | 41.1 |
| Interest rate swaps | Interest (US$) | 152.1 | 161.2 |
| Foreign currency forwards | Cdn$ | | 34.9 |

*Fair value of derivative instruments*

We have elected to disclose derivative instrument assets and liabilities on a trade-by-trade basis and do not offset amounts at the counterparty master agreement level. The following table summarizes the fair value of our derivative assets and liabilities:

| | December 31, 2014 | |
|---|---|---|
| | Derivative Assets | Derivative Liabilities |
| Derivative instruments designated as cash flow hedges: | | |
| Interest rate swaps current | $ | $ 1.1 |
| Interest rate swaps long-term | | 2.9 |
| Total derivative instruments designated as cash flow hedges | | 4.0 |
| Derivative instruments not designated as cash flow hedges: | | |
| Interest rate swaps current | | 5.1 |
| Interest rate swaps long-term | 1.5 | 17.3 |
| Foreign currency forward contracts current | | |
| Foreign currency forward contracts long-term | | |
| Natural gas swaps current | | 4.4 |
| Natural gas swaps long-term | | 2.2 |
| Gas purchase agreements current | | 28.6 |
| Gas purchase agreements long-term | | 35.5 |
| Total derivative instruments not designated as cash flow hedges | 1.5 | 93.1 |
| Total derivative instruments | $ 1.5 | $ 97.1 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**14. Accounting for derivative instruments and hedging activities (Continued)**

| | December 31, 2013 | |
|---|---|---|
| | Derivative Assets | Derivative Liabilities |
| Derivative instruments designated as cash flow hedges: | | |
| Interest rate swaps current | $ | $ 1.3 |
| Interest rate swaps long-term | | 2.6 |
| Total derivative instruments designated as cash flow hedges | | 3.9 |
| Derivative instruments not designated as cash flow hedges: | | |
| Interest rate swaps current | | 7.3 |
| Interest rate swaps long-term | 11.5 | 8.1 |
| Foreign currency forward contracts current | 0.5 | 0.7 |
| Foreign currency forward contracts long-term | 1.2 | |
| Natural gas swaps current | 0.3 | 1.3 |
| Natural gas swaps long-term | | 3.5 |
| Gas purchase agreements current | 0.2 | 18.4 |
| Gas purchase agreements long-term | | 61.9 |
| Total derivative instruments not designated as cash flow hedges | 13.7 | 101.2 |
| Total derivative instruments | $ 13.7 | $ 105.1 |

*Accumulated other comprehensive income*

The following table summarizes the changes in the accumulated other comprehensive income (loss) ("OCI") balance attributable to derivative financial instruments designated as a hedge, net of tax:

| For the year ended December 31, 2014 | Interest Rate Swaps |
|---|---|
| Accumulated OCI balance at January 1, 2014 | $ 0.2 |
| Change in fair value of cash flow hedges | (1.0) |
| Realized from OCI during the period | 0.9 |
| Accumulated OCI balance at December 31, 2014 | $ 0.1 |
| Gains expected to be realized from OCI in the next 12 months, net of $0.6 million of tax | $ 0.9 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**14. Accounting for derivative instruments and hedging activities (Continued)**

| For the year ended December 31, 2013 | Interest Rate Swaps | Natural Gas Swaps | Total |
|---|---|---|---|
| Accumulated OCI balance at January 1, 2013 | $ (1.5) | $ 0.1 | $ (1.4) |
| Change in fair value of cash flow hedges | 0.7 | | 0.7 |
| Realized from OCI during the period | 1.0 | (0.1) | 0.9 |
| Accumulated OCI balance at December 31, 2013 | $ 0.2 | $ | $ 0.2 |
| Gains expected to be realized from OCI in the next 12 months, net of $0.6 million of tax | $ 1.0 | $ | $ 1.0 |

| For the year ended December 31, 2012 | Interest Rate Swaps | Natural Gas Swaps | Total |
|---|---|---|---|
| Accumulated OCI balance at January 1, 2012 | $ (1.7) | $ 0.3 | $ (1.4) |
| Change in fair value of cash flow hedges | (0.9) | | (0.9) |
| Realized from OCI during the period | 1.1 | (0.2) | 0.9 |
| Accumulated OCI balance at December 31, 2012 | $ (1.5) | $ 0.1 | $ (1.4) |

*Impact of derivative instruments on the consolidated statements of operations*

The following table summarizes realized loss (gain) for derivative instruments not designated as cash flow hedges:

| | Classification of (gain) loss recognized in income | Year ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|---|
| Gas purchase agreements | Fuel | $ 52.4 | $ 56.5 | $ 43.5 |
| Natural gas swaps | Fuel | 4.3 | | |
| Interest rate swaps | Interest, net | (12.0) | (9.9) | (4.6) |
| Foreign currency forwards | Foreign exchange loss (gain) | 0.5 | (14.4) | (18.5) |

The following table summarizes the unrealized loss (gain) resulting from changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

**Year ended December 31,**

| | Classification of (gain) loss recognized in income | 2014 | 2013 | 2012 |
|---|---|---|---|---|
| Natural gas swaps | Change in fair value of derivatives | $ 3.3 | $ (0.7) | $ (1.2) |
| Gas purchase agreements | Change in fair value of derivatives | (11.6) | 19.2 | (57.0) |
| Interest rate swaps | Change in fair value of derivatives | 17.0 | 31.0 | (1.1) |
| | | $ 8.7 | $ 49.5 | $ (59.3) |
| Foreign currency forwards | Foreign exchange loss | $ 1.1 | $ 19.4 | $ 12.0 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**15. Income taxes**

| | Year ended December 31 | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Current income tax expense | $ 3.8 | $ 7.8 | $ 6.0 |
| Deferred tax benefit | (15.7) | (27.3) | (34.1) |
| Total income tax benefit, net | $ (11.9) | $ (19.5) | $ (28.1) |

The following is a reconciliation of income taxes calculated at the Canadian enacted statutory rate of 26%, 26%, and 25% at December 31, 2014, 2013 and 2012, respectively, to the provision for income taxes in the consolidated statements of operations:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Computed income taxes at Canadian statutory rate | $ (50.4) | $ (9.7) | $ (36.2) |
| Decreases resulting from: | | | |
| Operating countries with different income tax rates | (20.9) | (2.9) | (8.5) |
| | $ (71.3) | $ (12.6) | $ (44.7) |
| Change in valuation allowance | 40.5 | 12.1 | 20.2 |
| | (30.8) | (0.5) | (24.5) |
| Dividend withholding tax and other cash taxes | 0.8 | 3.7 | 5.9 |
| Foreign exchange | (7.4) | (9.9) | 1.5 |
| Permanent differences | | | (6.5) |
| Non-deductible acquisition costs | | | 0.6 |
| Changes in tax rates | (1.4) | (4.1) | 1.8 |
| Federal grant | | (18.9) | |
| Production tax credits | (0.2) | (4.5) | |
| Changes in estimates of tax basis of equity method investments | (4.1) | (1.4) | (5.1) |
| Capital loss recognized on tax restructuring | (10.2) | | |
| Goodwill impairment | 33.9 | 13.6 | |
| Minority Interest | 6.6 | | |
| Other | 0.9 | 2.5 | (1.8) |
| | 18.9 | (19.0) | (3.6) |
| | $ (11.9) | $ (19.5) | $ (28.1) |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**15. Income taxes (Continued)**

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2014 and 2013 are presented below:

| | 2014 | 2013 |
|---|---|---|
| Deferred tax assets: | | |
| Loss carryforwards | $ 340.3 | $ 254.1 |
| Other accrued liabilities | 0.4 | 0.4 |
| Finance and share issuance costs | 6.2 | 6.7 |
| Disallowed interest carryforward | 3.4 | 1.7 |
| Derivative contracts | 22.3 | 27.8 |
| Other | 10.3 | 8.0 |
| Total deferred tax assets | 382.9 | 298.7 |
| Valuation allowance | (168.6) | (128.1) |
| | 214.3 | 170.6 |
| Deferred tax liabilities: | | |
| Intangible assets | (75.0) | (74.2) |
| Property, plant and equipment | (208.9) | (194.8) |
| Other long-term investments | (22.8) | (13.1) |
| Total deferred tax liabilities | (306.7) | (282.1) |
| Net deferred tax liability | $ (92.4) | $ (111.5) |

The following table summarizes the net deferred tax position as of December 31, 2014 and 2013:

| | 2014 | 2013 |
|---|---|---|
| Long-term deferred tax liabilities | $ (92.4) | $ (111.5) |
| Net deferred tax liability | $ (92.4) | $ (111.5) |

As of December 31, 2014, we have recorded a valuation allowance of $168.6 million. This amount is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or the entire deferred tax asset will be realized. The ultimate realization of the deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

In 2011, the IRS began an examination of our federal income tax returns for the tax years ended December 31, 2007 and 2009. On April 2, 2012, the IRS issued various Notices of Proposed Adjustments. The principal area of the proposed adjustments pertain to the classification of U.S. real property in the calculation of the gain related to our 2009 conversion from the previous Income Participating Security structure to our current traditional common share structure. On September 14, 2014, we entered into a settlement agreement with the IRS resulting in a $3.6 million increase to our taxable income for the 2009 tax year. This increase in taxable income was offset against our current year taxable losses for the 2009 tax year and therefore resulted in no cash taxes.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**15. Income taxes (Continued)**

Tax benefits related to uncertain tax positions taken or expected to be taken on a tax return are recorded when such benefits meet a more likely than not threshold. Otherwise, these tax benefits are recorded when a tax position has been effectively settled, which means that the statute of limitation has expired or the appropriate taxing authority has completed their examination even though the statute of limitations remains open. Interest and penalties related to uncertain tax positions are recognized as part of the provision for income taxes and are accrued beginning in the period that such interest and penalties would be applicable under relevant tax law until such time that the related tax benefits are recognized. As of December 31, 2014, we have not recorded any tax benefits related to uncertain tax positions.

As of December 31, 2014, we had the following net operating loss carryforwards that are scheduled to expire in the following years:

| | |
|---|---|
| 2027 | $ 49.8 |
| 2028 | 98.1 |
| 2029 | 78.3 |
| 2030 | 25.8 |
| 2031 | 56.3 |
| 2032 | 79.1 |
| 2033 | 328.8 |
| 2034 | 158.3 |
| | $ 874.5 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

## 16. Equity compensation plans

*Long-term incentive plan*

The following table summarizes the changes in outstanding LTIP notional units during the years ended December 31, 2014, 2013 and 2012:

| | Units | Grant Date Weighted-Average Fair Value per Unit |
|---|---|---|
| Outstanding at December 31, 2011 | 485,781 | 11.49 |
| Granted | 233,752 | 14.67 |
| Additional shares from dividends | 38,667 | 13.43 |
| Forfeitures | (28,932) | 13.63 |
| Vested and redeemed | (236,733) | 10.18 |
| Outstanding at December 31, 2012 | 492,535 | 13.90 |
| Granted | 597,031 | 4.91 |
| Additional shares from dividends | 64,576 | 8.74 |
| Forfeitures | (184,458) | 8.17 |
| Vested and redeemed | (202,696) | 13.48 |
| Outstanding at December 31, 2013 | 766,988 | 7.86 |
| Granted | 1,776,083 | 2.64 |
| Additional shares from dividends | 178,114 | 3.79 |
| Forfeitures | (294,037) | 6.68 |
| Vested and redeemed | (983,894) | 4.78 |
| Outstanding at December 31, 2014 | 1,443,254 | $ 3.28 |

The fair value of all outstanding notional units under the LTIP was $4.6 million and $4.8 million for the years ended December 31, 2014 and 2013. Compensation expense related to LTIP was $3.5 million, $2.2 million and $2.5 million for the years ended December 31, 2014, 2013 and 2012, respectively. Cash payments made for vested notional units were $0.7 million, $0.9 million and $1.1 million for the years ended December 31, 2014, 2013 and 2012, respectively.

## 17. Defined benefit plan

We sponsor and operate a defined benefit pension plan that is available to certain legacy employees of the Partnership. The Atlantic Power Services Canada LP Pension Plan (the "Plan") is maintained solely for certain eligible legacy Partnership participants. The Plan is a defined benefit pension plan that allows for employee contributions. We expect to contribute $0.6 million to the pension plan in 2015.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**17. Defined benefit plan (Continued)**

The net annual periodic pension cost related to the pension plan for the years ended December 31, 2014 and 2013 includes the following components:

| | 2014 | 2013 |
|---|---|---|
| Service cost benefits earned | $ 0.8 | $ 0.9 |
| Interest cost on benefit obligation | 0.7 | 0.7 |
| Expected return on plan assets | (0.8) | (0.8) |
| Gain amortization | | 0.1 |
| Net period benefit cost | $ 0.7 | $ 0.9 |

A comparison of the pension benefit obligation and related plan assets for the pension plan is as follows:

| | 2014 | 2013 |
|---|---|---|
| Benefit obligation at January 1 | $ (14.5) | $ (16.8) |
| Service cost | (0.8) | (0.9) |
| Interest cost | (0.7) | (0.7) |
| Actuarial (gain) loss | (3.3) | 1.4 |
| Employee contributions | (0.1) | (0.1) |
| Benefits paid | 0.1 | 0.1 |
| Foreign currency translation adjustment | (0.1) | 1.0 |
| Benefit obligation at December 31 | (19.4) | (16.0) |
| Fair value of plan assets at January 1 | $ 13.8 | $ 12.0 |
| Actual return on plan assets | 1.7 | 1.8 |
| Employer contributions | 0.7 | 2.3 |
| Employee contributions | 0.1 | 0.1 |
| Benefits paid | (0.1) | (0.1) |
| Foreign currency translation adjustment | 0.1 | (1.0) |
| Fair value of plan assets at December 31 | 16.3 | 15.1 |
| Funded status at December 31 excess of obligation over assets | $ (3.1) | $ (0.9) |

Amounts recognized in the balance sheet were as follows:

| | 2014 | 2013 |
|---|---|---|
| Non-current liabilities | $ 3.1 | $ 0.9 |

Amounts recognized in accumulated OCI that have not yet been recognized as components of net periodic benefit cost were as follows, net of tax:

| | 2014 | 2013 |
|---|---|---|
| Unrecognized loss | $ 1.7 | $ 0.3 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**17. Defined benefit plan (Continued)**

We estimate that there will be no amortization of net loss for the pension plan from accumulated OCI to net periodic cost over the next fiscal year.

The following table presents the balances of significant components of the pension plan:

| | 2014 | 2013 |
|---|---|---|
| Projected benefit obligation | $ 19.4 | $ 16.0 |
| Accumulated benefit obligation | 15.4 | 12.4 |
| Fair value of plan assets | 16.3 | 15.1 |

The market-related value of the pension plan's assets is the fair value of the assets. Plan assets are invested in a common collective trust which totaled $16.3 million and $15.1 million for the years ended December 31, 2014 and 2013 respectively.

We determine the level in the fair value hierarchy within which the fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety. The fair value of the common/collective trust is valued at a fair value which is equal to the sum of the market value of the fund's investments, and is categorized as Level 2. There are no investments categorized as Level 1 or 3.

The following table presents the significant assumptions used to calculate our benefit obligations:

| | 2014 | 2013 |
|---|---|---|
| **Weighted-Average Assumptions** | | |
| Discount rate | 4.0% | 5.0% |
| Rate of compensation increase | 4.0% | 4.0% |

The following table presents the significant assumptions used to calculate our benefit expense:

| | 2014 | 2013 |
|---|---|---|
| **Weighted-Average Assumptions** | | |
| Discount rate | 5.0% | 4.0% |
| Rate of return on plan assets | 6.0% | 6.0% |
| Rate of compensation increase | 4.0% | 3.0% - 4.0% |

We use December 31 as the measurement date for the Plan, and we set the discount rate assumptions on an annual basis on the measurement date. This rate is determined by management based on information provided by our actuary. The discount rate assumptions reflect the current rate at which the associated liabilities could be effectively settled at the end of the year. The discount rate assumptions used to determine future pension obligations as of the year ended December 31, 2014 and 2013, was based on the CIA / Natcan curve, which was designed by the Canadian Institute of Actuaries and Natcan Investment Management to provide a means for sponsors of Canadian plans to value the liabilities of their postretirement benefit plans. The CIA / Natcan curve is a hypothetical yield curve represented by extrapolating the corporate AA-rated yield curve beyond 10 years using yields on provincial AA bonds with a spread added to the provincial AA yields to approximate the difference between corporate AA and provincial AA credit risk. The CIA / Natcan curve utilizes this approach

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**17. Defined benefit plan (Continued)**

because there are very few corporate bonds rated AA or above with maturities of 10 years or more in Canada.

We employ a balanced total return investment approach, whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, and the plan's funded status. Plan assets in the common collective trust are currently invested in a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across Canadian, U.S. and other international equities, as well as among growth, value and small and large capitalization stocks.

The pension plan assets weighted average allocations in the common collective trust were as follows:

| | 2014 | 2013 |
|---|---|---|
| Canadian equity | 30% | 30% |
| U.S. equity | 14% | 17% |
| International equity | 13% | 15% |
| Canadian fixed income | 40% | 38% |
| International fixed income | 3% | 0% |
| | 100% | 100% |

Our expected future benefit payments for each of the next five years and in the aggregate for the five years thereafter, are as follows in Cdn$:

| | 2014 |
|---|---|
| 2015 | $ 0.2 |
| 2016 | 0.3 |
| 2017 | 0.3 |
| 2018 | 0.4 |
| 2019 | 0.5 |
| 2020-2023 | 4.1 |

**18. Common shares**

On July 5, 2012, we closed a public offering of 5,567,177 common shares, at a purchase price of $12.76 per common share and Cdn$13.10 per common share, for an aggregate net proceeds from the common share offering, after deducting the underwriting discounts and expenses, of approximately $68.5 million. We used the proceeds to fund our equity commitment in Canadian Hills.

***Shelf Registrations***

On August 8, 2012, we filed with the SEC an automatic shelf registration statement (Registration No. 333-183135) for the potential offering and sale of debt and equity securities, including common shares issued under our dividend reinvestment program. At that time, because we were a well-known seasoned issuer, as defined in Rule 405 under the Securities Act, the registration statement was

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**18. Common shares (Continued)**

effective immediately upon filing. As a result of the decrease in our market capitalization, we can no longer offer and sell securities under that shelf registration. However, in February 2014, we filed a new registration statement, which became effective immediately upon filing, for the continued and uninterrupted issuance of common shares under our dividend reinvestment program.

**19. Preferred shares issued by a subsidiary company**

In 2007, a subsidiary acquired in our acquisition of the Partnership issued 5.0 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Shares") priced at Cdn$25.00 per share. Cumulative dividends are payable on a quarterly basis at the annual rate of Cdn$1.2125 per share. Beginning on June 30, 2012, the Series 1 Shares were redeemable by the subsidiary company at Cdn$26.00 per share, declining by Cdn$0.25 each year to Cdn$25.00 per share on or after June 30, 2016, plus, in each case, an amount equal to all accrued and unpaid dividends thereon.

In 2009, a subsidiary company acquired in our acquisition of the Partnership issued 4.0 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the "Series 2 Shares") priced at Cdn$25.00 per share. The Series 2 Shares pay fixed cumulative dividends of Cdn$1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate reset on December 31, 2014 and will reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. On December 31, 2014 and on December 31 every five years thereafter, the Series 2 Shares were and will be redeemable by the subsidiary company at Cdn$25.00 per share, plus an amount equal to all declared and unpaid dividends thereon to, but excluding the date fixed for redemption. The holders of the Series 2 Shares had and will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the" Series 3 Shares") of the subsidiary, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the subsidiary, at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate and 4.18%. On December 31, 2014 1,661,906 of Series 2 shares were converted to Series 3 shares.

The Series 1 Shares, the Series 2 Shares and the Series 3 Shares are fully and unconditionally guaranteed by us and by the Partnership on a subordinated basis as to: (i) the payment of dividends, as and when declared; (ii) the payment of amounts due on a redemption for cash; and (iii) the payment of amounts due on the liquidation, dissolution or winding up of the subsidiary company. If, and for so long as, the declaration or payment of dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares is in arrears, the Partnership will not make any distributions on its limited partnership units and we will not pay any dividends on our common shares.

The subsidiary company paid aggregate dividends of $11.6 million on the Series 1 Shares and the Series 2 Shares in 2014 as compared to $12.6 million in 2013.

**20. Basic and diluted earnings (loss) per share**

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**20. Basic and diluted earnings (loss) per share (Continued)**

potential shares include shares that would be issued if all of the convertible debentures were converted into shares at January 1, 2014. Dilutive potential shares also include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

Because we reported a loss for the years ended December 31, 2014, 2013 and 2012, diluted earnings per share are equal to basic earnings per share as the inclusion of potentially dilutive shares in the computation is anti-dilutive.

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the years ended December 31, 2014, 2013 and 2012:

| | 2014 | 2013 | 2012 |
|---|---|---|---|
| **Numerator:** | | | |
| Loss from continuing operations attributable to Atlantic Power Corporation | $ (177.3) | $ (27.4) | $ (128.5) |
| (Loss) income from discontinued operations, net of tax | (0.1) | (5.6) | 15.7 |
| Net loss attributable to Atlantic Power Corporation | $ (177.4) | $ (33.0) | $ (112.8) |
| **Denominator:** | | | |
| Weighted average basic shares outstanding | 120.7 | 119.9 | 116.4 |
| Dilutive potential shares: | | | |
| Convertible debentures | 27.7 | 27.7 | 17.4 |
| LTIP notional units | 0.3 | 0.7 | 0.5 |
| Potentially dilutive shares | 148.7 | 148.3 | 134.3 |
| Diluted loss per share from continuing operations attributable to Atlantic Power Corporation | $ (1.47) | $ (0.23) | $ (1.10) |
| Diluted (loss) earnings per share from discontinued operations | | (0.05) | 0.13 |
| Diluted loss per share attributable to Atlantic Power Corporation | $ (1.47) | $ (0.28) | $ (0.97) |

Potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units have been excluded from fully diluted shares in the years ended December 31, 2014, 2013 and 2012 because their impact would be anti-dilutive.

**21. Discontinued operations**

On March 6, 2014, we sold our outstanding membership interests in Greeley for approximately $1.0 million and recorded a $2.1 million non-cash gain on the sale related to the write-off of asset retirement obligations. Greeley is accounted for as a component of discontinued operations in the consolidated statements of operations for the years ended December 31, 2014, 2013, and 2012, respectively.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**21. Discontinued operations (Continued)**

On November 5, 2013, we completed the sale of our 60% interest in Rollcast to its remaining shareholders. As consideration for the sale, we were assigned asset management contracts valued at $0.5 million for the Cadillac and Piedmont projects as well as the remaining 2% ownership interest in Piedmont bringing our total ownership to 100%. In return, we paid $0.5 million in cash to the minority owner and forgave an outstanding $1.0 million loan that was provided by us to Rollcast to fund working capital during 2013. Rollcast's net loss is recorded as loss from discontinued operations in the consolidated statements of operations for the years ended December 31, 2013 and 2012.

The Florida Projects and Path 15 were sold on April 12, 2013 and April 30, 2013, respectively. Accordingly, the projects' net income (loss) is recorded as income (loss) from discontinued operations, net of tax in the statements of operations for the years ended December 31, 2013, and 2012.

The following tables summarize the revenue, loss from operations, and income tax expense of Greeley, Rollcast, Path 15 and the Florida Projects for the three and years ended December 31, 2014, 2013, and 2012:

| | December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Revenue | $ | $ 79.2 | $ 227.3 |
| (Loss) income from discontinued operations | (0.1) | (4.8) | 17.5 |
| Income tax expense | | 0.8 | 1.8 |
| (Loss) income from discontinued operations, net of tax | $ (0.1) | $ (5.6) | $ 15.7 |

Basic and diluted earnings (loss) per share related to income (loss) from discontinued operations for the Florida Projects, Path 15, Greeley and Rollcast was $0.00, ($0.05), and $0.13 for the years ended December 31, 2014, 2013, and 2012 respectively.

**22. Segment and geographic information**

We have four reportable segments: East, West, Wind and Un-allocated Corporate. We revised our reportable business segments in the fourth quarter of 2013 as a result of significant project asset sales and in order to align our reportable business segments with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. Our financial results for the year ended December 31, 2012 have been presented to reflect these changes in operating segments. We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. Our equity investments in unconsolidated affiliates are presented on a proportionally consolidated basis in Project Adjusted EBITDA and in the reconciliation of Project Adjusted EBITDA to project income (loss). Greeley and Path 15, which are

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**22. Segment and geographic information (Continued)**

components of the West segment, the Florida Projects, which are components of the East segment, and Rollcast, which is a component of Un-allocated Corporate, are included in the income (loss) from discontinued operations line item in the table below. We have adjusted prior periods to reflect this reclassification. A reconciliation of Project Adjusted EBITDA to project income (loss) is included in the table below:

| | East | West | Wind | Un-allocated Corporate | Consolidated |
|---|---|---|---|---|---|
| **Year ended December 31, 2014** | | | | | |
| Project revenues | $ 313.8 | $ 175.2 | $ 79.3 | $ 0.9 | $ 569.2 |
| Segment assets | 1,177.2 | 831.9 | 866.1 | 41.4 | 2,916.6 |
| Goodwill | 84.7 | 112.5 | | | 197.2 |
| Capital expenditures | 10.8 | 1.7 | 0.9 | | 13.4 |
| Project Adjusted EBITDA | $ 158.5 | $ 78.5 | $ 69.8 | $ (7.5) | $ 299.3 |
| Change in fair value of derivative instruments | (7.3) | | 16.5 | 1.2 | 10.4 |
| Depreciation and amortization | 90.8 | 64.4 | 45.8 | 0.7 | 201.7 |
| Interest, net | 20.5 | | 19.0 | | 39.5 |
| Other project expense | 32.7 | 65.4 | | 0.1 | 98.2 |
| Project income (loss) | 21.8 | (51.3) | (11.5) | (9.5) | (50.5) |
| Administration | | | | 37.9 | 37.9 |
| Interest, net | | | | 146.7 | 146.7 |
| Foreign exchange gain | | | | (38.3) | (38.3) |
| Other income, net | | | | (2.8) | (2.8) |
| Income (loss) from continuing operations before income taxes | 21.8 | (51.3) | (11.5) | (153.0) | (194.0) |
| Income tax benefit | | | | (11.9) | (11.9) |
| Net income (loss) from continuing operations | 21.8 | (51.3) | (11.5) | (141.1) | (182.1) |
| Loss from discontinued operations | | (0.1) | | | (0.1) |
| Net income (loss) | $ 21.8 | $ (51.4) | $ (11.5) | $ (141.1) | $ (182.2) |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**22. Segment and geographic information (Continued)**

| | East | West | Wind | Un-allocated Corporate | Consolidated |
|---|---|---|---|---|---|
| **Year ended December 31, 2013** | | | | | |
| Project revenues | $ 299.1 | $ 174.7 | $ 70.8 | $ (0.5) | $ 544.1 |
| Segment assets | 1,395.2 | 1,001.5 | 853.9 | 144.4 | 3,395.0 |
| Goodwill | 107.8 | 188.5 | | | 296.3 |
| Capital expenditures | 13.8 | 1.1 | 11.1 | 0.2 | 26.2 |
| Project Adjusted EBITDA | $ 150.7 | $ 77.2 | $ 59.6 | $ (18.6) | $ 268.9 |
| Change in fair value of derivative instruments | (24.4) | | (25.9) | | (50.3) |
| Depreciation and amortization | 93.7 | 67.3 | 47.3 | 0.5 | 208.8 |
| Interest, net | 20.7 | 0.4 | 19.5 | (2.1) | 38.5 |
| Other project expense (income) | 34.9 | (26.3) | 0.1 | (0.5) | 8.2 |
| Project income (loss) | 25.8 | 35.8 | 18.6 | (16.5) | 63.7 |
| Administration | | | | 35.2 | 35.2 |
| Interest, net | | | | 104.1 | 104.1 |
| Foreign exchange gain | | | | (27.4) | (27.4) |
| Other income, net | | | | (10.5) | (10.5) |
| Income (loss) from continuing operations before income taxes | 25.8 | 35.8 | 18.6 | (117.9) | (37.7) |
| Income tax benefit | | | | (19.5) | (19.5) |
| Net income (loss) from continuing operations | 25.8 | 35.8 | 18.6 | (98.4) | (18.2) |
| (Loss) income from discontinued operations | (1.1) | 1.9 | | (6.4) | (5.6) |
| Net income (loss) | $ 24.7 | $ 37.7 | $ 18.6 | $ (104.8) | $ (23.8) |

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**22. Segment and geographic information (Continued)**

| | East | West | Wind | Un-allocated Corporate | Consolidated |
|---|---|---|---|---|---|
| **Year ended December 31, 2012** | | | | | |
| Project revenues | $ 267.5 | $ 159.0 | $ 1.9 | $ 1.4 | $ 429.8 |
| Segment assets | 1,600.2 | 1,305.3 | 956.3 | 140.9 | 4,002.7 |
| Goodwill | 138.6 | 192.6 | | 3.5 | 334.7 |
| Capital expenditures | 25.5 | 0.2 | 441.6 | 0.8 | 468.1 |
| Project Adjusted EBITDA | $ 145.7 | $ 78.9 | $ 10.9 | $ (11.1) | $ 224.4 |
| Change in fair value of derivative instruments | 56.6 | | | | 56.6 |
| Depreciation and amortization | 87.5 | 70.0 | 5.9 | 0.1 | 163.5 |
| Interest, net | 18.5 | 0.4 | 5.1 | | 24.0 |
| Other project expense | 1.2 | 3.0 | 7.3 | | 11.5 |
| Project (loss) income | (18.1) | 5.5 | (7.4) | (11.2) | (31.2) |
| Administration | | | | 28.3 | 28.3 |
| Interest, net | | | | 89.8 | 89.8 |
| Foreign exchange loss | | | | 0.5 | 0.5 |
| Other income, net | | | | (5.7) | (5.7) |
| (Loss) income from continuing operations before income taxes | (18.1) | 5.5 | (7.4) | (124.1) | (144.1) |
| Income tax benefit | | | | (28.1) | (28.1) |
| Net (loss) income from continuing operations | (18.1) | 5.5 | (7.4) | (96.0) | (116.0) |
| Income (loss) from discontinued operations | 13.6 | 4.7 | | (2.6) | 15.7 |
| Net (loss) income | $ (4.5) | $ 10.2 | $ (7.4) | $ (98.6) | $ (100.3) |

The table below provides information, by country, about our consolidated operations for each of the years ended December 31, 2014, 2013 and 2012 and Property, Plant & Equipment as of December 31, 2014 and 2013, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

| | Revenue | | | Property, Plant & Equipment, net | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2014 | 2013 |
| United States | $ 370.9 | $ 335.5 | $ 216.6 | $ 1,264.0 | $ 1,330.5 |
| Canada | 198.3 | 208.6 | 213.2 | 409.4 | 482.9 |
| Total | $ 569.2 | $ 544.1 | $ 429.8 | $ 1,673.4 | $ 1,813.4 |

Independent Electricity System Operator ("IESO"), San Diego Gas & Electric, and BC Hydro provided 25.8%, 15.1%, and 9.1%, respectively, of total consolidated revenues for the year ended December 31, 2014. IESO, San Diego Gas & Electric and BC Hydro provided for 27.7%, 14.4%, and 10.1% of total consolidated revenues for the year ended December 31, 2013. IESO purchases electricity from the Calstock, Kapuskasing, Nipigon, North Bay and Tunis projects in the East segment. San Diego Gas & Electric purchases electricity from the Naval Station, Naval Training Center, and North Island projects in the West segment. BC Hydro purchases electricity from the Mamquam, Moresby

Lake, and Williams Lake projects in the West segment.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**23. Commitments and contingencies**

***Commitments***

***Operating Lease Commitments***

We lease our office properties and equipment under operating leases expiring on various dates through 2021. Certain operating lease agreements over their lease term include provisions for scheduled rent increases. We recognize the effects of these scheduled rent increases on a straight-line basis over the lease term. Lease expense under operating leases was $1.0 million, $1.0 million and $2.0 million for the years ended December 31, 2014, 2013, and 2012, respectively. Future minimum lease commitments under operating leases for the years ending after December 31, 2014, are as follows:

| | |
|---|---|
| 2015 | $ 1.4 |
| 2016 | 1.4 |
| 2017 | 1.3 |
| 2018 | 1.2 |
| 2019 | 1.2 |
| Thereafter | 4.5 |
| | $ 11.0 |

***Long-Term Service Commitments***

Our projects have entered into long-term contractual arrangements to obtain maintenance services for turbine equipment expiring on various dates through 2022. As of December 31, 2014, our commitments under such outstanding agreements are estimated as follows:

| | |
|---|---|
| 2015 | $ 5.1 |
| 2016 | 5.1 |
| 2017 | 5.1 |
| 2018 | 5.1 |
| 2019 | 5.1 |
| Thereafter | 19.4 |
| | $ 44.9 |

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**23. Commitments and contingencies (Continued)**

***Fuel Supply and Transportation Commitments***

We have entered into long-term contractual arrangements to procure fuel and transportation services for our projects. As of December 31, 2014, our commitments under such outstanding agreements are estimated as follows:

| | | |
|---|---|---|
| 2015 | $ | 69.8 |
| 2016 | | 63.8 |
| 2017 | | 24.2 |
| 2018 | | 16.7 |
| 2019 | | 12.4 |
| Thereafter | | 37.2 |
| | $ | 224.1 |

***Contingencies***

*Shareholder class action lawsuits*

Massachusetts District Court Actions

On March 8, 14, 15 and 25, 2013 and April 23, 2013, five purported securities fraud class action complaints were filed by alleged investors in Atlantic Power common shares in the United States District Court for the District of Massachusetts (the "District Court") against Atlantic Power and Barry E. Welch, our former President and Chief Executive Officer and a former Director of Atlantic Power, in each of the actions, and, in addition to Mr. Welch, some or all of Patrick J. Welch, our former Chief Financial Officer, Lisa Donahue, our former interim Chief Financial Officer, and Terrence Ronan, our current Chief Financial Officer, in certain of the actions (the "Proposed Individual Defendants," and together with Atlantic Power, the "Proposed Defendants") (the "U.S. Actions").

The District Court complaints differed in terms of the identities of the Proposed Individual Defendants they named, as noted above, the named plaintiffs, and the purported class period they alleged (July 23, 2010 to March 4, 2013 in three of the District Court actions and August 8, 2012 to February 28, 2013 in the other two District Court actions), but in general each alleged, among other things, that in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, Atlantic Power and the Proposed Individual Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The District Court complaints assert claims under Section 10(b) and, against the Proposed Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended.

The parties to each District Court action filed joint motions requesting that the District Court set a schedule in the District Court actions, including: (i) setting a deadline for the lead plaintiff to file a consolidated amended class action complaint (the "Amended Complaint"), after the appointment of lead plaintiff and counsel; (ii) setting a deadline for Proposed Defendants to answer, file a motion to dismiss or otherwise respond to the Amended Complaint (and for subsequent briefing regarding any

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**23. Commitments and contingencies (Continued)**

such motion to dismiss); and (iii) confirming that the Proposed Defendants need not answer, move to dismiss or otherwise respond to any of the five District Court complaints prior to the filing of the Amended Complaint. On May 7, 2013, each of six groups of investors (the "U.S. Lead Plaintiff Applicants") filed a motion (collectively, the "U.S. Lead Plaintiff Motions") with the District Court seeking: (i) to consolidate the five U.S. Actions (the "Consolidated U.S. Action"); (ii) to be appointed lead plaintiff in the Consolidated U.S. Action; and (iii) to have its choice of lead counsel confirmed. On May 22, 2013, three of the U.S. Lead Plaintiff Applicants filed oppositions to the other U.S. Lead Plaintiff Motions, and on June 6, 2013, those three Lead Plaintiff Applicants filed replies in support of their respective motions. On August 19, 2013, the District Court held a status conference to address certain issues raised by the U.S. Lead Plaintiff Motions, entered an order consolidating the five U.S. Actions, and directed two of the six U.S. Lead Plaintiff Applicants to file supplemental submissions by September 9, 2013. Both of those U.S. Lead Plaintiff Applicants filed the requested supplemental submissions, and then sought leave to file additional briefing. The Court granted those requests for leave and additional submissions were filed on September 13 and September 18, 2013.

On March 31, 2014, the Court entered an order consolidating the five individual U.S. Actions, appointing the Feldman, Shapero, Carter and Smith investor group (one of the six U.S. Lead Plaintiffs Applicants) as Lead Plaintiff and approving Lead Plaintiff's selection of counsel. The Court also granted the parties' joint motion regarding initial case scheduling and directed the parties to resubmit a proposed schedule that contains specific dates. In response to that directive, on April 7, 2014, Lead Plaintiff filed an application and proposed order, which sought an extension of the schedule contained in the joint motion. The application and proposed order requested that: (i) Lead Plaintiff be permitted to file an amended complaint on or before May 30, 2014, (ii) the Proposed Defendants be permitted to move to dismiss or otherwise respond to the amended complaint on or before July 29, 2014, (iii) Lead Plaintiff be permitted to file an opposition, if any, on or before September 24, 2014, and (iv) the Proposed Defendants be permitted to file a reply to Lead Plaintiff's opposition on or before November 13, 2014. Proposed Defendants did not object to the schedule proposed by Lead Plaintiff. On May 29, 2014, Lead Plaintiff filed a renewed application and proposed order, which sought another extension of the schedule, and on June 3, 2014, Lead Plaintiff and the Proposed Defendants jointly filed a stipulation and proposed order requesting the following revised schedule: (i) Lead Plaintiff be permitted to file an amended complaint on or before June 6, 2014, (ii) the Proposed Defendants be permitted to move to dismiss or otherwise respond to the amended complaint on or before August 5, 2014, (iii) Lead Plaintiff be permitted to file an opposition, if any, on or before October 6, 2014, and (iv) the Proposed Defendants be permitted to file a reply to Lead Plaintiff's opposition on or before November 20, 2014. On June 3, 2014, the Court entered an order setting this requested schedule.

On June 6, 2014, Lead Plaintiff filed the amended complaint (the "Amended Complaint"). The Amended Complaint names as defendants Barry E. Welch and Terrence Ronan (the "Individual Defendants") and Atlantic Power (together with the Individual Defendants, the "Defendants") and alleges a class period of June 20, 2011 to March 4, 2013 (the "Class Period"). The Amended Complaint makes allegations that are substantially similar to those asserted in the five initial complaints. Specifically, the Amended Complaint alleges, among other things, that in Atlantic Power's press releases, quarterly and year- end filings and conference calls with analysts and investors, Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share dividend, which artificially inflated the price of Atlantic Power's common shares

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**23. Commitments and contingencies (Continued)**

during the class period. The Amended Complaint continues to assert claims under Section 10(b) and, against the Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended. It also asserts a claim for unjust enrichment against the Individual Defendants. In accordance with the schedule referenced above, Defendants filed their motion to dismiss the consolidated (the "Motion to Dismiss") U.S. Action on August 5, 2014.

On September 30, 2014, citing Atlantic Power's September 16, 2014 announcement of changes to its dividend and its President and CEO transition, Lead Plaintiff filed a motion (the "Extension Motion") requesting a thirty-day extension of its October 6, 2014 deadline for filing its brief in opposition to the Motion to Dismiss, in which to determine whether to file a second amended complaint. On October 2, 2014, the Court entered an order (i) extending Lead Plaintiff's deadline to file its opposition to the Motion to Dismiss to October 10, 2014 and (ii) requiring Defendants to file their opposition to the Extension Motion by October 2, 2014. In accordance with this order, on October 2, 2014, Defendants filed their opposition to the Extension Motion. On October 10, 2014, Lead Plaintiff filed its opposition to the Motion to Dismiss (the "Opposition") and also filed a motion for leave to amend the Amended Complaint, attaching a proposed second amended complaint. On October 21, 2014, Lead Plaintiff and Defendants filed a joint scheduling motion requesting (i) November 7, 2014 as the deadline for Defendants to file their opposition to Lead Plaintiff's motion for leave to amend the Amended Complaint; (ii) November 24, 2014 as the deadline for Defendants to file their reply in further support of the Motion to Dismiss; and (iii) November 24, 2014 as the deadline for Lead Plaintiff to file its reply in further support of its motion for leave to amend the Amended Complaint. On October 22, 2014, the Court entered an order setting this requested schedule. Pursuant to that order, the Motion to Dismiss and Extension Motion were fully briefed on November 24, 2014. On January 22, 2015, the Court held oral argument on the Motion to Dismiss and Extension Motion.

On January 30, 2015, Lead Plaintiff filed a motion for leave to file a supplemental submission in opposition to Defendants' motion to dismiss (the "Motion for Leave"). The Court denied the Motion for Leave in an order entered on February 5, 2015, but permitted Lead Plaintiff to submit a brief letter identifying supplemental authorities. Lead Plaintiff filed that letter on February 9, 2015, and Defendants filed a response on February 10, 2015.

Canadian Actions

On March 19, 2013, April 2, 2013 and May 10, 2013, three notices of action relating to Canadian securities class action claims against the Proposed Defendants were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, with the Ontario Superior Court of Justice in the Province of Ontario. On April 8, 2013, a similar claim issued by alleged investors in Atlantic Power common shares seeking to initiate a class action against the Proposed Defendants was filed with the Superior Court of Quebec in the Province of Quebec (the "Canadian Actions").

On April 17, May 22, and June 7, 2013 statements of claim relating to the notices of action were filed with the Ontario Superior Court of Justice in the Province of Ontario.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**23. Commitments and contingencies (Continued)**

On August 30, 2013, the three Ontario actions were succeeded by one action with an amended claim being issued on behalf of Jacqeline Coffin and Sandra Lowry. As in the U.S. Action, this claim names the Company, Barry E. Welch and Terrence Ronan as Defendants. The Plaintiffs seeks leave to commence an action for statutory misrepresentation under the Ontario Securities Act and asserts common law claims for misrepresentation. The Plaintiffs' allegations focus on among other things, claims the Defendants made materially false and misleading statements and omissions in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The Plaintiffs seek to certify the statutory and common law claims under the Class Proceedings Act for security holders who purchased and held securities through a proposed class period of November 5, 2012 to February 28, 2013.

On October 4, 2013, the Plaintiffs delivered materials supporting their request for leave to commence an action for statutory misrepresentations and for certification of the statutory and common claims as class proceedings. These materials estimate the damages claimed for statutory misrepresentation at $197.4 million.

Between June 2014 and January 2015, the Defendants and Plaintiffs exchanged responding and reply materials.

A schedule for the Plaintiffs' leave and certification motions was set in December 2014. It provides for a hearing of the Plaintiffs' motions on May 20-21, 2015.

The proposed class action in Quebec is stayed until March 30, 2015.

Pursuant to the Private Securities Litigation Reform Act of 1995, all discovery is stayed in the U.S. Actions. Plaintiffs have not yet specified an amount of alleged damages in the U.S. Actions. As noted above, the plaintiffs in the Canadian Action have estimated their alleged statutory damages at $197.4 million. Because both the U.S. and Canadian Actions are in their early stages, Atlantic Power is unable to reasonably estimate the possible loss or range of losses, if any, arising from this litigation. Atlantic Power intends to defend vigorously against each of the actions.

*Other*

In addition to the other matters listed, from time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of December 31, 2014.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

## 24. Unaudited selected quarterly financial data

Unaudited selected quarterly financial data are as follows:

| | Quarter Ended 2014 | | | | |
|---|---|---|---|---|---|
| | December 31, | September 30, | June 30, | March 31, | Total |
| Project revenue | $ 142.4 | $ 138.3 | $ 143.2 | $ 145.3 | $ 569.2 |
| Project (loss) income | 1.9 | (68.6) | (3.8) | 20.0 | (50.5) |
| Loss from continuing operations | (12.2) | (91.1) | (56.4) | (22.4) | (182.1) |
| Loss from discontinued operations | | | | (0.1) | (0.1) |
| Net loss attributable to Atlantic Power Corporation | (10.4) | (88.9) | (59.2) | (18.9) | (177.4) |
| Loss per share from continuing operations attributable to Atlantic Power Corporation | $ (0.08) | $ (0.74) | $ (0.49) | $ (0.16) | $ (1.47) |
| Loss per share from discontinued operations | | | | | |
| Loss per share attributable to Atlantic Power Corporation | $ (0.08) | $ (0.74) | $ (0.49) | $ (0.16) | $ (1.47) |
| Weighted average number of common shares outstanding-basic | 121.0 | 120.7 | 120.6 | 120.3 | 120.8 |
| Diluted loss per share from continuing operations attributable to Atlantic Power Corporation | $ (0.08) | $ (0.74) | $ (0.49) | $ (0.16) | $ (1.47) |
| Diluted loss per share from discontinued operations | | | | | |
| Diluted loss per share attributable to Atlantic Power Corporation | $ (0.08) | $ (0.74) | $ (0.49) | $ (0.16) | $ (1.47) |
| Weighted average number of common shares outstanding-diluted[1] | 121.0 | 120.7 | 120.6 | 120.3 | 120.8 |

(1) The calculation excludes potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units because their impact would be anti-dilutive.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**24. Unaudited selected quarterly financial data (Continued)**

| | Quarter Ended 2013 | | | | |
|---|---|---|---|---|---|
| | December 31, | September 30, | June 30, | March 31, | Total |
| Project revenue | $ 130.7 | $ 140.0 | $ 136.0 | $ 137.4 | $ 544.1 |
| Project income | 7.8 | 4.4 | 20.2 | 31.3 | 63.7 |
| Income (loss) from continuing operations | 8.7 | (40.6) | 6.6 | 7.1 | (18.2) |
| (Loss) income from discontinued operations | (0.9) | | (5.4) | 0.7 | (5.6) |
| Net income (loss) attributable to Atlantic Power Corporation | 4.8 | (41.3) | (3.0) | 6.5 | (33.0) |
| Income (loss) per share from continuing operations attributable to Atlantic Power Corporation | $ 0.04 | $ (0.34) | $ 0.02 | $ 0.05 | $ (0.23) |
| Loss per share from discontinued operations | | | (0.05) | | (0.05) |
| Income (loss) per share attributable to Atlantic Power Corporation | $ 0.04 | $ (0.34) | $ (0.03) | $ 0.05 | $ (0.28) |
| Weighted average number of common shares outstanding-basic | 120.1 | 120.0 | 119.9 | 119.5 | 119.9 |
| Diluted income (loss) per share from continuing operations attributable to Atlantic Power Corporation | $ 0.04 | $ (0.34) | $ 0.02 | $ 0.05 | $ (0.23) |
| Diluted loss per share from discontinued operations | | | (0.05) | | (0.05) |
| Diluted income (loss) per share attributable to Atlantic Power Corporation | $ 0.04 | $ (0.34) | $ (0.03) | $ 0.05 | $ (0.28) |
| Weighted average number of common shares outstanding-diluted[1] | 120.1 | 120.0 | 119.9 | 119.5 | 119.9 |

(1) The calculation excludes potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units because their impact would be anti-dilutive.

**25. Guarantees**

In connection with the tax equity investments in our Canadian Hills project, we have expressly indemnified the investors for certain representations and warranties made by a wholly-owned subsidiary with respect to matters which we believe are remote and improbable to occur. The expiration dates of these guarantees vary from less than one year through the indefinite termination date of the project. Our maximum undiscounted potential exposure is limited to the amount of tax equity investment less cash distributions made to the investors and any amount equal to the net federal income tax benefits arising from production tax credits.

We and our subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchases and sale agreements, joint venture agreements, operation and maintenance agreements, and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

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**ATLANTIC POWER CORPORATION**

**SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS**

**FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012**

**(in millions of U.S. dollars)**

| | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions | Balance at End of Period |
|---|---|---|---|---|---|
| **Income tax valuation allowance, deducted from deferred tax assets:** | | | | | |
| Year ended December 31, 2014 | $ 128.1 | $ 40.5 | $ | $ | $ 168.6 |
| Year ended December 31, 2013 | 116.0 | 12.1 | | | 128.1 |
| Year ended December 31, 2012 | 89.0 | 20.2 | 6.8 | | 116.0 |