

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following management's discussion and analysis of financial condition and results of operations should be read in conjunction with our audited consolidated financial statements included in this Annual Report on Form 10-K. All dollar amounts discussed below are in millions of U.S. dollars, unless otherwise stated. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").

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

Overview of Our Business

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.

We sell the majority of the capacity and energy from our power generation projects under PPAs to a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from December 31, 2017 to December 31, 2037, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects to industrial purchasers under steam sales agreements. Sales of electricity are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating.

The majority of our natural gas, coal and biomass power generation projects have long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the term of the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is no pass-through of fuel costs, we often attempt to mitigate the market price risk of changing commodity costs through the use of hedging strategies.

We directly operate and maintain twenty-one of our power generation projects. We also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including CEM and PPMS. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

Our organization

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 previously reported financial results for the year ended December 31, 2012 has been presented to reflect these changes in operating segments. The segment classified as Un-allocated Corporate includes activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects and intercompany eliminations. These costs are not allocated to the operating segments when determining segment profit or loss. Project income (loss) is the primary GAAP measure of our operating results and is discussed below by reportable segment.

Our strategy and execution of our business plan

We continue to focus on executing our business plan objectives and have been focused on initiatives aimed at, among other things, improving our financial flexibility and addressing our near-term maturities.

As announced in the third quarter of 2014, as part of our previously announced strategic review process, we concluded that a sale or merger of the Company was not in the best interests of the Company or its stakeholders. With the assistance of its external financial advisors, Goldman, Sachs & Co. and Greenhill & Co., LLC, our Board of Directors conducted a thorough review of the options available to the Company with respect to a possible sale or merger. The Board of Directors determined that the interests of the Company and its stakeholders are best served by continuing to operate as an independent company and executing our business plan. This plan includes the objectives of delevering our balance sheet to improve our cost of capital and ability to compete for new investments, enhancing the value of our existing assets through discretionary capital investments and commercial activities, utilizing our core competencies to create proprietary investment opportunities, improving our cost structure and reducing overhead. In addition, we continue to assess other potential options, including asset sales or the contribution of assets to a joint venture if the valuation of a particular asset or assets is compelling, and to raise additional capital for growth or potential debt reduction.

Delevering our balance sheet and improving financial flexibility

In February 2014, we executed the Term Loan Facility and used the funds therefrom to address debt maturities in 2014, 2015 and 2017 as discussed in more detail in "—Liquidity and Capital Resources". The 50% cash sweep and amortization features of the Term Loan Facility are expected to reduce leverage over time. During 2014 we paid down \$58.4 million of principal through the cash sweep and amortization. With a portion of the proceeds received from the Term Loan Facility, we paid down \$140.1 million aggregate principal amount of the 9.0% Notes. In January 2015, we also repurchased an additional \$9.0 million of the 9.0% Notes. Also, as previously announced in the third quarter of 2014, our Board of Directors determined to set a dividend level of Cdn\$0.12 per share on an annual basis, equivalent to approximately \$13 million annually. Dividends to shareholders are paid, if and when declared by, and subject to the discretion of, the Board of Directors. As we execute our business strategy, and consistent with our objectives, our Board of Directors, together with our management, will regularly evaluate what the optimal dividend policy is for the Company going forward.

On October 31, 2014, we used Cdn\$44.8 million of cash on hand to repay at maturity our 6.5% Convertible Secured Debentures due October 31, 2014. Additionally, we have targeted opportunistic market purchases of our outstanding debt securities. We believe these purchases have the benefit of reducing financial risk and lowering cost of capital. 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 have repurchased and cancelled \$3.1 million par value of convertible debentures with \$2.6 million of cash on-hand. In January and February 2015, we also repurchased and cancelled an additional \$6.1 million par value of convertible debentures with \$4.9 million of cash on-hand.

Investment in our existing businesses and extension of our contracts

We continue to make both mandatory maintenance and optimization investments in our existing fleet designed to improve longevity, safety and efficiency, boost output or reduce costs. During 2014, we invested \$33.2 million in maintenance and capital expenditures, of which approximately \$17.2 million was for optimization projects. We are targeting funding approximately \$35.0 million of maintenance and capital expenditures during 2015, of which between \$10 and \$15 million will be discretionary investments aimed at improving the projects' economics.

On January 20, 2015, we entered into an agreement with the Ontario Power Authority ("OPA") and its successor, IESO, for the future operations of the Tunis facility. Subject to meeting certain technical modifications to the plant, gas delivery and other requirements, Tunis will operate under a 15-year agreement with the IESO commencing between November 2017 and June 2019. The new contract will require the plant to become fully dispatchable as opposed to its current baseload configuration. As such, Tunis will only provide electricity to the Ontario grid when required, thereby assisting to reduce the incidents of surplus baseload generation in the market. The new agreement provides the Tunis project with a fixed monthly payment which escalates annually according to a pre-defined formula while allowing it to earn additional energy revenues for those periods during which it is called upon to operate.

Improving our cost structure and reducing overhead

Beginning in 2013 and throughout 2014, we took aggressive actions to reduce corporate expenses in the areas of personnel, development and administrative costs. We expect these actions to result in a savings of at least \$15 million in corporate general and administrative and development expenses in 2015 as compared to amounts incurred in 2013 (our baseline year for comparison). As a result of these actions, we incurred \$6.0 million of employee severance costs and \$4.9 million of other non-recurring costs in 2014. In addition, we also expect to incur approximately \$2.2 million of employee severance costs in the first quarter of 2015. We will continue to evaluate improvements to our cost structure.

Management and oversight

We concluded our search for a President and Chief Executive Officer. On January 22, 2015, our Board of Directors appointed James J. Moore, Jr., as President, Chief Executive Officer and a director of the Company, effective January 26, 2015. In connection with Mr. Moore's appointment, effective January 26, 2015, Kenneth Hartwick stepped down as Interim President and CEO. Mr. Hartwick remains a member of the Board of Directors of the Company. During the fourth quarter of 2014, the Board also appointed two new independent directors of the company: Teresa M. Ressel and Kevin T. Howell. With these additions, our Board of Directors now consists of eight members, seven of whom are independent under applicable stock exchange and SEC standards.

Other significant events during the year ended December 31, 2014

Zachry Arbitration

In October 2014, we settled a dispute in arbitration with Zachry, the contractor of Piedmont, related to work performed under the project's engineering, procurement and construction contract ("EPC"). The settlement reflects payment for the completion of the contract. Under the terms of the settlement, Piedmont agreed to pay Zachry \$5.0 million within seven days of execution of the settlement agreement. The settlement results in a mutual release of all arbitration claims by both parties. Piedmont had accrued \$8.2 million for the final retainage payment under the EPC in 2013. On November 5, 2014, Piedmont made a \$5.0 million payment from restricted cash related to the settlement agreement, while the remaining \$3.2 million of reversed accrual was credited to operations and maintenance expense which was originally accrued in 2013.

Goodwill Impairment

During the three months ended June 30, 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 a test of the remaining goodwill at all of our reporting units. We completed this during the third quarter of 2014 and determined that goodwill was impaired at the Kenilworth (East segment), Manchief (West Segment) and Williams Lake (West segment) reporting units. The total non-cash impairment recorded in the three and nine months ended September 30, 2014 was \$91.8 million. We updated this test in the fourth quarter in connection with our annual test as of November 30, 2014 and recorded no additional impairment.

Under our accounting policies for long-lived assets and goodwill impairment, we 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 assets impairment test and a goodwill impairment test during the second quarter of 2014. Based on the results of these tests, the project recorded a \$9.6 million long-lived impairment charge and a \$5.2 million goodwill impairment charge in the second quarter of 2014. The \$14.8 million aggregate long-lived asset and goodwill impairment was primarily due to our assessment of the forecasted cash flows from re-contracting and other strategic outcomes at Tunis. We anticipate that forecasted cash flows under Tunis' new PPA are expected to recover the remaining long-lived asset balance at the project.

Sale of 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 as a component of equity in earnings of unconsolidated affiliates in the consolidated statement of operations. 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.

Expiration of Selkirk PPA

The PPA at Selkirk (in which our economic ownership interest is 18.5%) expired as of August 31, 2014. This resulted in 100% of the project's capacity not being contracted. As of August 31, 2014, Selkirk began operating on a 100% merchant basis, with the project selling power into the spot power market to the extent spot market prices support profitable operation of the project.

Performance highlights

	Year Ended December 31,		
	2014	2013	2012
Project (loss) income	\$ (50.5)	\$ 63.7	\$ (31.2)
Loss from continuing operations	\$ (182.1)	\$ (18.2)	\$ (116.0)
(Loss) income from discontinued operations	\$ (0.1)	\$ (5.6)	\$ 15.7
Net loss attributable to Atlantic Power Corporation	\$ (177.4)	\$ (33.0)	\$ (112.8)
Loss per share from continuing operations attributable to Atlantic Power Corporation—basic and diluted	\$ (1.47)	\$ (0.23)	\$ (1.10)
Earnings (loss) per share from discontinued operations—basic	—	(0.05)	0.13
Loss per share attributable to Atlantic Power Corporation—basic and diluted	\$ (1.47)	\$ (0.28)	\$ (0.97)
Project Adjusted EBITDA ⁽¹⁾	\$ 299.3	\$ 268.9	\$ 224.4
Free Cash Flow ⁽¹⁾	\$ (55.6)	\$ 108.8	\$ 131.6

(1) See reconciliation and definition below under Supplementary Non-GAAP Financial Information.

Consolidated project loss was \$(50.5) million for the year ended December 31, 2014, a decrease of \$114.2 million from the prior year. The decrease was primarily due to \$71.7 million increase in non-cash goodwill and long-lived asset impairments, a \$58.2 million increase in non-cash loss on changes in the fair value of derivatives and a \$21.8 million decrease in the gain in sale of equity method projects from the comparable 2013 period, partially offset by a \$25.1 million increase in revenue from strong wind and waste heat generation and lower development and general and administrative expenses. Project Adjusted EBITDA, a non-GAAP measure, increased \$30.4 million for the year ended December 31, 2014. This increase was driven by strong wind generation, increased waste heat at our Ontario projects and lower maintenance and administrative expenses as compared to a year ago. This was partially offset by lower dispatch at several plants due to mild summer weather. A detailed discussion of project (loss) income by segment is provided in Consolidated Overview and Results of Operations below. The discussion of Project Adjusted EBITDA by segment begins on page 71.

Factors That May Influence Our Results

The primary components of our financial results are (i) the financial performance of our projects, (ii) unrealized gains and losses associated with derivative instruments, (iii) interest expense and foreign exchange impacts on corporate-level debt, and (iv) impairment of long-lived assets and goodwill. We have recorded net losses for the past five years, primarily as a result of non-cash losses associated with items (ii), (iii) and (iv) above, which are described in more detail in the following paragraphs.

Financial performance of our projects

The operating performance of our projects supports cash distributions that are made to us after all operating, maintenance, capital expenditures and debt service requirements are satisfied at the project-level. Our projects are able to generate cash flows because they generally receive revenues from long-term contracts that provide relatively stable cash flows. Risks to the stability of these distributions include the following:

- Power generated by our projects, in most cases, is sold under PPAs that expire at various times. Currently, our PPAs are scheduled to expire between December 31, 2017 and December 31, 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA on acceptable terms or timing, if at all, or the price received by the project for power under

subsequent arrangements may be reduced significantly, or there may be a delay in securing a new PPA until a significant time after the expiration of the original PPA at the project. For example, the PPA at Selkirk expired in August 2014. As a result, 100% of the capacity at Selkirk is not contracted and therefore sold at market power prices. Our next PPA expirations do not occur until year end 2017 and are at our North Bay and Kapuskasing projects in Ontario. See "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."

- While approximately 28% of our power generation revenue in 2014 was related to contractual capacity payments, commodity prices do influence our variable revenues and the cost of fuel. Our PPAs are generally structured to minimize our risk to fluctuations in commodity prices by passing the cost of fuel through to the utility and its customers, but some of our projects do have exposure to market power and fuel 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" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our hedging arrangements.
- Our most significant exposure to market power prices exists at the Selkirk, Chambers and Morris projects. At Chambers, our utility customer has the right to sell a portion of the plant's output to the spot power market if it is economical to do so, and the Chambers project shares in the profits from those sales. With low demand for electricity the utility reduces its dispatch to minimum contracted levels during off-peak hours. At Selkirk, none of the capacity of the facility is currently contracted and is sold at market power prices or not sold at all if market prices do not support profitable operation of that portion of the facility. Additionally at Morris, approximately 68% of the facility's capacity is currently not contracted and is sold at market power prices or not sold at all if market prices do not support profitable operation of the facility. See Item 1A. "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."
- When revenue or fuel contracts at our projects expire, we may not be able to sell power or procure fuel under new arrangements that provide the same level or stability of project cash flows. If re-contracted, the degree of the expected decline in cash flows from operations is subject to market conditions when we execute new PPAs for these projects and is difficult to estimate at this time. 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." These projects will be free of debt when their PPAs expire, which we expect to provide us with some flexibility to pursue the most economic type of contract without restrictions that might be imposed by project-level debt.
- Some of our projects have non-recourse project-level debt that can restrict the ability of the project to make cash distributions. The project-level debt agreements typically contain cash flow coverage ratio tests that restrict the project's cash distributions if project cash flows do not exceed project-level debt service requirements by a specified amount. Although all projects, with the exception of Piedmont, are currently meeting these debt service requirements, we cannot provide any assurances that these projects will generate enough future cash flow to meet any applicable ratio tests and be able to make distributions to us. See "Liquidity and Capital Resources—Project-level debt" and Item 1A. "Risk Factors—Risks Related to Our Structure—Our indebtedness and financing arrangements, and any failure to comply with the covenants

contained therein, could negatively impact our business and our projects and could render us unable to make dividend payments, acquisitions or investments or issue additional indebtedness we otherwise would seek to do."

- The performance of our projects is impacted by a variety of operational and other factors, including planned and unplanned outages and maintenance requirements, delays in start-up, sourcing of fuel from suppliers and wind, water and waste heat levels, among others. For example, delays in the start-up of our Piedmont project and subsequent unplanned outages have resulted in increased costs and lost revenue and have affected our results. For additional details regarding the various operational and other risks that we face, see "Risk Factors—Risks Related to Our Business and Our Projects."

Non-cash gains and losses on derivatives instruments

In the ordinary course of our business, we execute natural gas purchase agreements and natural gas swap contracts to manage our exposure to fluctuations in commodity prices, foreign currency forward contracts to manage our exposure to fluctuations in foreign exchange rates and interest rate swaps to manage our exposure to changes in interest rates on variable rate project-level debt. Most of these contracts are recorded at fair value with changes in fair value recorded currently in earnings, resulting in significant volatility in our income that does not significantly affect current period cash flows or the underlying risk management purpose of the derivative instruments. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our derivative instruments.

Interest expense and other costs associated with debt

Interest expense relates to both non-recourse project-level debt and corporate-level debt. A portion of our convertible debentures and long-term corporate level debt are denominated in Canadian dollars. These debt instruments are revalued at each balance sheet date based on the U.S. dollar to Canadian dollar foreign exchange rate at the balance sheet date, with changes in the value of the debt recorded in the consolidated statements of operations. The U.S. dollar to Canadian dollar foreign exchange rate has been volatile in recent years, which in turn creates volatility in our results due to the revaluation of our Canadian dollar-denominated debt.

Impairment

We test our long-lived assets and goodwill for impairment at least annually, or more often if deemed appropriate based on the determination of management or the occurrence of certain trigger events under our impairment policy. We recorded \$106.6 million and \$34.9 million of long-lived asset and goodwill impairments for the years ended December 31, 2014 and 2013, respectively.

Consolidated Overview and Results of Operations

2014 compared to 2013

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

	Years Ended December 31,			
	2014	2013	\$ change	% change
Project revenue:				
Energy sales	\$ 315.9	\$ 302.2	\$ 13.7	5%
Energy capacity revenue	161.3	163.7	(2.4)	-1%
Other	92.0	78.2	13.8	18%
	<u>569.2</u>	<u>544.1</u>	<u>25.1</u>	<u>5%</u>
Project expenses:				
Fuel	210.4	194.3	16.1	8%
Operations and maintenance	130.2	150.8	(20.6)	-14%
Development	3.7	7.2	(3.5)	NM
Depreciation and amortization	162.6	166.1	(3.5)	-2%
	<u>506.9</u>	<u>518.4</u>	<u>(11.5)</u>	<u>-2%</u>
Project other income (expense):				
Change in fair value of derivative instruments	(8.7)	49.5	(58.2)	-118%
Equity in earnings of unconsolidated affiliates	25.8	26.9	(1.1)	-4%
Gain on sale of equity investments	8.6	30.4	(21.8)	-72%
Interest expense, net	(31.9)	(34.4)	2.5	-7%
Impairment	(106.6)	(34.9)	(71.7)	NM
Other income, net	—	0.5	(0.5)	NM
	<u>(112.8)</u>	<u>38.0</u>	<u>(150.8)</u>	<u>NM</u>
Project (loss) income	<u>(50.5)</u>	<u>63.7</u>	<u>(114.2)</u>	<u>NM</u>
Administrative and other expenses (income):				
Administration	37.9	35.2	2.7	8%
Interest, net	146.7	104.1	42.6	41%
Foreign exchange gain	(38.3)	(27.4)	(10.9)	40%
Other income, net	(2.8)	(10.5)	7.7	-73%
	<u>143.5</u>	<u>101.4</u>	<u>42.1</u>	<u>42%</u>
Loss from continuing operations before income taxes	(194.0)	(37.7)	(156.3)	NM
Income tax benefit	(11.9)	(19.5)	7.6	-39%
Loss from continuing operations	(182.1)	(18.2)	(163.9)	901%
Loss from discontinued operations, net of tax	(0.1)	(5.6)	5.5	-98%
Net loss	(182.2)	(23.8)	(158.4)	NM
Net loss attributable to noncontrolling interests	(16.4)	(3.4)	(13.0)	NM
Net income attributable to Preferred share dividends of a subsidiary company	11.6	12.6	(1.0)	-8%
Net loss attributable to Atlantic Power Corporation	<u>\$ (177.4)</u>	<u>\$ (33.0)</u>	<u>\$ (144.4)</u>	<u>NM</u>

Project Income (Loss) by Segment

	Year Ended December 31, 2014				
	East	West ⁽²⁾	Wind	Un-allocated Corporate	Consolidated Total
Project revenue:					
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
	<u>313.8</u>	<u>175.2</u>	<u>79.3</u>	<u>0.9</u>	<u>569.2</u>
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
	<u>271.9</u>	<u>164.4</u>	<u>61.4</u>	<u>9.2</u>	<u>506.9</u>
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	—	—	—	—	—
	<u>(20.1)</u>	<u>(62.1)</u>	<u>(29.4)</u>	<u>(1.2)</u>	<u>(112.8)</u>
Project income (loss)	<u>\$ 21.8</u>	<u>\$ (51.3)</u>	<u>\$ (11.5)</u>	<u>\$ (9.5)</u>	<u>\$ (50.5)</u>

	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
	<u>299.1</u>	<u>174.7</u>	<u>70.8</u>	<u>(0.5)</u>	<u>544.1</u>
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
	<u>267.6</u>	<u>169.6</u>	<u>62.6</u>	<u>18.6</u>	<u>518.4</u>
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
	<u>(5.7)</u>	<u>30.7</u>	<u>10.4</u>	<u>2.6</u>	<u>38.0</u>
Project income (loss)	<u>\$ 25.8</u>	<u>\$ 35.8</u>	<u>\$ 18.6</u>	<u>\$ (16.5)</u>	<u>\$ 63.7</u>

(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.

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.

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.

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.

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%
	<u>544.1</u>	<u>429.8</u>	<u>114.3</u>	<u>27%</u>
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%
	<u>518.4</u>	<u>401.1</u>	<u>117.3</u>	<u>29%</u>
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
	<u>38.0</u>	<u>(59.9)</u>	<u>97.9</u>	<u>NM</u>
Project income (loss)	<u>63.7</u>	<u>(31.2)</u>	<u>94.9</u>	<u>NM</u>
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%
	<u>101.4</u>	<u>112.9</u>	<u>(11.5)</u>	<u>-10%</u>
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	<u>\$ (33.0)</u>	<u>\$ (112.8)</u>	<u>\$ 79.8</u>	<u>-71%</u>

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
	<u>299.1</u>	<u>174.7</u>	<u>70.8</u>	<u>(0.5)</u>	<u>544.1</u>
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
	<u>267.6</u>	<u>169.6</u>	<u>62.6</u>	<u>18.6</u>	<u>518.4</u>
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
	<u>(5.7)</u>	<u>30.7</u>	<u>10.4</u>	<u>2.6</u>	<u>38.0</u>
Project income (loss)	<u>\$ 25.8</u>	<u>\$ 35.8</u>	<u>\$ 18.6</u>	<u>\$ (16.5)</u>	<u>\$ 63.7</u>

	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
	<u>267.5</u>	<u>159.0</u>	<u>1.9</u>	<u>1.4</u>	<u>429.8</u>
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
	<u>237.4</u>	<u>150.0</u>	<u>1.1</u>	<u>12.6</u>	<u>401.1</u>
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)
	<u>(48.2)</u>	<u>(3.5)</u>	<u>(8.2)</u>	<u>—</u>	<u>(59.9)</u>
Project income (loss)	<u>\$ (18.1)</u>	<u>\$ 5.5</u>	<u>\$ (7.4)</u>	<u>\$ (11.2)</u>	<u>\$ (31.2)</u>

(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

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.

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.

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

(in Net MWh)	Year ended December 31,				
	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.

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

Segment	Year ended December 31,				
	2014	2013	2012	% change 2014 vs. 2013	% change 2013 vs. 2012
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.

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.

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,				
	2014	2013	2012	% change 2014 vs. 2013	% change 2013 vs. 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

- \$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.

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.

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.

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:

	<u>Years ended December 31,</u>		
	<u>2014</u>	<u>2013</u>	<u>2012</u>
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.

Consolidated Cash Flows

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

	Year ended December 31,		Change
	2014	2013	
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.

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	<u>\$ 255.8</u>	<u>\$ 325.6</u>

- (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.

Corporate Debt Service Obligations

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

	<u>Maturity Date</u>	<u>Interest Rates</u>	<u>Remaining Principal Repayments</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>Thereafter</u>
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 L Note	June 2036	6.0%	181.0	—	—	—	—	—	181.0
Convertible Debentur	March 2017	6.3%	58.0	—	—	58.0	—	—	—
Convertible Debentur	June 2017	5.6%	68.7	—	—	68.7	—	—	—
Convertible Debentur	June 2019	5.8%	128.2	—	—	—	—	128.2	—
Convertible Debentur	December 2019	6.0%	85.7	—	—	—	—	85.7	—
Total Corporate Debt			<u>\$ 1,383.0</u>	<u>\$ 5.4</u>	<u>\$ 5.4</u>	<u>\$ 132.1</u>	<u>\$ 325.3</u>	<u>\$ 219.3</u>	<u>\$ 695.5</u>

(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



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.

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.

	<u>Maturity Date</u>	<u>Range of Interest Rates</u>	<u>Total Remaining Principal Repayments</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>Thereafter</u>
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 Consolidate 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

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%.

- (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.

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.

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 unit 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.

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

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.

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.

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

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.

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.