
**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): **April 21, 2015**

ATLANTIC POWER CORPORATION

(Exact name of registrant as specified in its charter)

British Columbia, Canada
(State or other jurisdiction of
incorporation or organization)

001-34691
(Commission File Number)

55-0886410
(IRS Employer Identification No.)

3 Allied Drive, Suite 220
Dedham, MA
(Address of principal executive offices)

02026
(Zip Code)

(617) 977-2400
(Registrant's telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

- ☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
 - ☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
 - ☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
 - ☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))
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Item 7.01 Regulation FD Disclosure.

On April 21, 2015, Atlantic Power Limited Partnership (“APLP”), a wholly-owned indirect subsidiary of Atlantic Power Corporation (the “Company”), will provide to the lenders under its senior secured credit facilities the consolidated financial statements of APLP for the years ended December 31, 2014 and 2013 (the “APLP Financial Statements”), which are attached hereto as Exhibit 99.1 and incorporated by reference herein. The APLP Financial Statements have been prepared in accordance with generally accepted accounting principles in the United States and are expressed in U.S. dollars. The information in this Item 7.01, including Exhibit 99.1, should be read in conjunction with the information contained in the Company’s filings under the Securities Exchange Act of 1934, as amended (the “Exchange Act”).

The information in this Item 7.01, including Exhibit 99.1, is being furnished and shall not be deemed to be “filed” for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that Section, nor shall such information be deemed to be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, or the Exchange Act, except as otherwise stated in that filing. The Company does not undertake any obligation to update the information contained in this Item 7.01, including Exhibit 99.1.

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits*

Exhibit Number	Description
99.1	Consolidated Financial Statements of APLP for the years ended December 31, 2014 and 2013.

SIGNATURES

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

Atlantic Power Corporation

Dated: April 21, 2015

By: /s/ Terrence Ronan

Name: Terrence Ronan

Title: *Chief Financial Officer*

EXHIBIT INDEX

Exhibit Number	Description
99.1	Consolidated Financial Statements of APLP for the years ended December 31, 2014 and 2013.

ATLANTIC POWER LIMITED PARTNERSHIP

Consolidated Financial Statements

December 31, 2014 and 2013

(With Independent Auditors' Report Thereon)

ATLANTIC POWER LIMITED PARTNERSHIP

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KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Board of Directors and Shareholders
Atlantic Power Limited Partnership:

We have audited the accompanying consolidated financial statements of Atlantic Power Limited Partnership and subsidiaries, which comprise the consolidated balance sheets as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive loss, partner's equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly in all material respects, the financial position of Atlantic Power Limited Partnership and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

KPMG LLP

New York, New York
April 20, 2015

KPMG LLP is a Delaware limited liability partnership, the U.S. member firm of KPMG International Cooperative ("KPMG International"), a Swiss entity.

ATLANTIC POWER LIMITED PARTNERSHIP

CONSOLIDATED BALANCE SHEETS

December 31, 2014 and 2013

(in millions of U.S. dollars)

	2014	2013
Assets		
Current assets:		
Cash and cash equivalents (Note 2)	\$ 50.2	\$ 29.8
Accounts receivable	46.4	49.5
Current portion of derivative instruments asset (Note 13)	—	0.2
Inventory (Note 6)	16.2	13.1
Prepayments and other current assets	10.6	10.4
Refundable income taxes	0.7	4.1
Total current assets	<u>124.1</u>	<u>107.1</u>
Property, plant, and equipment, net (Note 7)	791.1	882.4
Equity investment in unconsolidated affiliate (Note 2 and 5)	135.0	153.8
Power purchase agreements and intangible assets, net (Note 9)	348.4	416.3
Goodwill (Note 8)	197.2	296.3
Derivative instruments asset (Notes 13)	1.1	1.2
Deferred financing costs (Note 2)	36.5	—
Other assets	9.0	9.9
Total assets	<u>\$ 1,642.4</u>	<u>\$ 1,867.0</u>
Liabilities		
Current liabilities:		
Accounts payable	\$ 7.9	\$ 9.1
Related party payables (Note 19)	57.8	25.3
Accrued interest	0.2	10.5
Other accrued liabilities	20.5	30.1
Current portion of long-term debt (Note 11)	5.6	190.2
Current portion of derivative instruments liability (Note 13)	29.7	18.7
Dividends payable	—	3.1
Other current liabilities	6.8	5.2
Total current liabilities	<u>128.5</u>	<u>292.2</u>
Long-term debt (Note 11)	717.5	423.1
Derivative instruments liability (Note 13)	35.4	61.9
Deferred income taxes (Note 14)	91.1	106.2
Power purchase and fuel supply agreement liabilities, net (Note 9)	33.4	38.7
Other long-term liabilities (Note 10)	53.8	59.2
Total liabilities	<u>1,059.7</u>	<u>981.3</u>
Commitments and contingencies (Note 18)	—	—
Equity		
Partner's capital	1,020.1	1,011.6
Preferred shares issued by a subsidiary company (Note 15)	221.3	221.3
Accumulated other comprehensive loss	(65.9)	(22.2)
Retained deficit	(592.8)	(325.0)
Total equity	<u>582.7</u>	<u>885.7</u>
Total liabilities and equity	<u>\$ 1,642.4</u>	<u>\$ 1,867.0</u>

See accompanying notes to consolidated financial statements.

ATLANTIC POWER LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF OPERATIONS

Years ended December 31, 2014 and 2013

(in millions of U.S. dollars)

	<u>2014</u>	<u>2013</u>
Project revenue:		
Energy sales	\$ 217.6	\$ 216.1
Energy capacity revenue	133.4	138.1
Other	90.2	76.7
	<u>441.2</u>	<u>430.9</u>
Project expenses:		
Fuel	188.4	179.8
Operations and maintenance	88.6	113.5
Depreciation and amortization	110.7	115.2
	<u>387.7</u>	<u>408.5</u>
Project other income (expense):		
Change in fair value of derivative instruments (Notes 12 and 13)	10.4	19.2
Equity in earnings of unconsolidated affiliates	2.2	2.1
Interest expense, net	(6.2)	(11.2)
Impairment of goodwill and long-lived assets (Note 8)	(106.6)	(34.9)
Other income, net	—	0.9
	<u>(100.2)</u>	<u>(23.9)</u>
Project loss	(46.7)	(1.5)
Administrative and other expenses (income):		
Administration	0.4	0.4
Interest, net	69.0	25.4
Foreign exchange gain	(18.6)	(9.4)
Other expense, net	16.0	13.9
	<u>66.8</u>	<u>30.3</u>
Loss from continuing operations before income taxes	(113.5)	(31.8)
Income tax benefit (Note 14)	(8.6)	(10.3)
Loss from continuing operations	(104.9)	(21.5)
Income from discontinued operations, net of tax (Note 16)	2.0	0.9
Net loss	(102.9)	(20.6)
Net income attributable to preferred shares dividends of a subsidiary company	11.6	12.6
Net loss attributable to Atlantic Power Limited Partnership	<u>\$ (114.5)</u>	<u>\$ (33.2)</u>

See accompanying notes to consolidated financial statements.

ATLANTIC POWER LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

Years ended December 31, 2014 and 2013

(in millions of U.S. dollars)

	2014	2013
Net loss	\$ (102.9)	\$ (20.6)
Foreign currency translation adjustments	(43.7)	(34.8)
Other comprehensive loss	(43.7)	(34.8)
Less: Comprehensive income attributable to noncontrolling interest	11.6	12.6
Comprehensive loss attributable to Atlantic Power Limited Partnership	<u>\$ (158.2)</u>	<u>\$ (68.0)</u>

See accompanying notes to consolidated financial statements.

ATLANTIC POWER LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF PARTNER'S EQUITY

Years ended December 31, 2014 and 2013

(in millions of U.S. dollars)

	Partners' Capital	Retained Deficit	Accumulated Other Comprehensive Income (loss)	Preferred Shares of a Subsidiary Company	Total Partners' Equity
December 31, 2012	\$ 1,010.6	\$ (211.8)	\$ 12.6	\$ 221.3	\$ 1,032.7
Net (loss) income	—	(33.2)	—	12.6	(20.6)
Contributions from Parent	1.0	—	—	—	1.0
Distributions to Parent	—	(80.0)	—	—	(80.0)
Dividends declared	—	—	—	(12.6)	(12.6)
Foreign currency translation adjustment	—	—	(34.8)	—	(34.8)
December 31, 2013	\$ 1,011.6	\$ (325.0)	\$ (22.2)	\$ 221.3	\$ 885.7
Net (loss) income	—	(114.5)	—	11.6	(102.9)
Contributions from Parent	8.5	—	—	—	8.5
Distributions to Parent	—	(153.3)	—	—	(153.3)
Dividends declared	—	—	—	(11.6)	(11.6)
Foreign currency translation adjustment	—	—	(43.7)	—	(43.7)
December 31, 2014	<u>\$ 1,020.1</u>	<u>\$ (592.8)</u>	<u>\$ (65.9)</u>	<u>\$ 221.3</u>	<u>\$ 582.7</u>

See accompanying notes to consolidated financial statements.

ATLANTIC POWER LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF CASH FLOWS
Years ended December 31, 2014 and 2013
(in millions of U.S. dollars)

	<u>2014</u>	<u>2013</u>
Cash flows from operating activities:		
Net loss	\$ (102.9)	\$ (20.6)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	110.7	116.2
Goodwill impairment charges	106.6	34.9
Gain on sale of assets	(2.1)	—
Equity in earnings from unconsolidated affiliates	(2.2)	(2.1)
Distributions from unconsolidated affiliates	21.1	—
Unrealized foreign exchange (gain) loss	(18.6)	(3.0)
Change in fair value of derivative instruments	(10.4)	(19.2)
Change in deferred income taxes	(12.3)	(15.9)
Change in other operating balances		
Accounts receivable	3.1	18.7
Inventory	(3.1)	2.5
Prepayments, supplies and other assets	8.3	(1.4)
Accounts payable	31.3	8.6
Accruals and other liabilities	(22.1)	(5.7)
Cash provided by operating activities	<u>107.4</u>	<u>113.0</u>
Cash used in investing activities:		
Proceeds from sale of assets	1.0	—
Purchase of property, plant and equipment	(13.8)	(5.9)
Cash used in investing activities	<u>(12.8)</u>	<u>(5.9)</u>
Cash flows used in financing activities:		
Proceeds from senior secured term loan facility	600.0	—
Repayment of corporate and project-level debt	(473.8)	(0.1)
Contributions from Parent	8.5	1.0
Distributions to Parent	(153.3)	(80.0)
Deferred financing costs	(40.7)	—
Dividends paid	(14.9)	(9.5)
Cash flows used in financing activities	<u>(74.2)</u>	<u>(88.6)</u>
Net increase in cash and cash equivalents	20.4	18.5
Cash and cash equivalents at beginning of period	29.8	11.3
Cash and cash equivalents at end of period	<u>\$ 50.2</u>	<u>\$ 29.8</u>
Supplemental cash flow information		
Interest paid	\$ 71.1	\$ 36.2
Taxes paid	\$ 3.8	\$ 5.9

See accompanying notes to consolidated financial statements.

ATLANTIC POWER LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in millions of U.S. dollars)

1. Nature of business

General

Atlantic Power Limited Partnership (the “Partnership”) (formerly Capital Power Income L.P.) is a limited partnership created under the laws of the Province of Ontario pursuant to a Partnership Agreement dated March 27, 1997, as amended and restated on November 4, 2009. The Partnership commenced operations on June 18, 1997 and currently has independent power generating facilities in British Columbia, Ontario, California, Colorado, Illinois, New Jersey, New York and Washington State. The Partnership is a wholly-owned subsidiary of Atlantic Power Corporation (“Atlantic Power” or the “Parent”); its registered address is One Federal St, Floor 30, Boston, MA 02110.

The Partnership has evaluated subsequent events from the balance sheet date through April 20, 2015, which is the date these financial statements were available for issuance.

The table on the following page outlines the portfolio of power generating assets in operation as of April 20, 2015, including the Partnership’s interest in each facility. Management believes the portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region. The Partnership’s customers are generally large utilities and other parties with investment-grade credit ratings, as measured by Standard & Poor’s (“S&P”). For customers rated by Moody’s, the Partnership substitutes the corresponding S&P rating in the table below. Customers that have assigned ratings at the top end of the range of investment-grade have, in the opinion of the rating agency, the strongest capability for payment of debt or payment of claims, while customers at the lower end of the range of investment-grade have weaker capacity.

Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)
East Segment								
Morris	Illinois	Natural Gas	177	100.00%	120	Merchant	N/A	N/R
Kenilworth	New Jersey	Natural Gas	25	100.00%	57	Equistar Chemicals, LP(4)	November 2023	BBB+
Curtis Palmer	New York	Hydro	60	100.00%	25	Merck, & Co., Inc.	September 2018	AA
Calstock	Ontario	Biomass	60	100.00%	60	Niagara Mohawk Power Corporation	December 2027 (2)	A-
Kapuskasing	Ontario	Natural Gas	35	100.00%	35	Ontario Electricity Financial Corp	June 2020	AA-
Nipigon	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	December 2017	AA-
North Bay	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	December 2022	AA-
Tunis(3)	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	December 2017	AA-
			43	100.00%	43	Ontario Electricity Financial Corp	December 2014	AA-
West Segment								
Naval Station	California	Natural Gas	47	100.00%	47	San Diego Gas & Electric	December 2019	A
Naval Training Center	California	Natural Gas	25	100.00%	25	San Diego Gas & Electric	December 2019	A
North Island	California	Natural Gas	42	100.00%	42	San Diego Gas & Electric	December 2019	A
Oxnard	California	Natural Gas	49	100.00%	49	Southern California Edison	May 2020	BBB+
Manchief	Colorado	Natural Gas	300	100.00%	300	Public Service Company of Colorado	April 2022	A-
Frederickson(1)	Washington	Natural Gas	250	50.15%	50	Benton Co. PUD	August 2022	A+
					45	Grays Harbor PUD	August 2022	A
					30	Franklin, Co. PUD	August 2022	A
Mamquam	British Columbia	Hydro	50	100.00%	50	British Columbia Hydro and Power Authority	September 2027	AAA
Moresby Lake	British Columbia	Hydro	6	100.00%	6	British Columbia Hydro and Power Authority	August 2022	AAA
Williams Lake	British Columbia	Biomass	66	100.00%	66	British Columbia Hydro and Power Authority	March 2018	AAA

- (1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.
- (2) The Curtis Palmer PPA expires at the earlier of December 2027 or the provision of 10,000 GWh of generation. From January 6, 1995 through December 31, 2014, the facility has generated 6,404 GWh under its PPA.
- (3) On January 20, 2015, the Partnership entered into an agreement with the Ontario Power Authority and its successor, the Independent Electricity System Operator ("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.
- (4) Represents the credit rating of LyondellBasell, the parent company of Equistar Chemicals as Equistar is not rated.

2. Summary of significant accounting policies

- (a) Principles of consolidation and basis of presentation:

The accompanying consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the consolidated accounts and operations of subsidiaries in which the Partnership has a controlling financial interest. The usual condition for a controlling

financial interest is ownership of the majority of the voting interest of an entity. However, a controlling financial interest may also exist in entities, such as a variable interest entity, through arrangements that do not involve controlling voting interests.

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

(b) Cash and cash equivalents:

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

(c) Deferred financing costs:

Deferred financing costs represent costs to obtain the Partnership’s new senior secured term loan facility (the “Senior Secured Term Loan Facility”) and are amortized using the effective interest method over the term of the Term Loan Facility which ranges from 4 to 7 years. The net carrying amount of deferred financing costs recorded on the consolidated balance sheet was \$36.5 million at December 31, 2014. Interest expense from the amortization of deferred finance costs for the year ended December 31, 2014 was \$4.2 million.

(d) Inventory:

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

(e) Property, plant and equipment:

Property, plant and equipment are stated at cost, net of accumulated depreciation. Depreciation is provided on a straight-line basis over the estimated useful life of the related asset, up to 45 years. Significant additions or improvements extending asset lives are capitalized as incurred, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred.

(f) Intangible assets:

Intangible assets include Power Purchase Agreements (“PPAs”) and fuel supply agreements at the projects. PPAs are valued at the time of acquisition based on the contract prices under the PPAs compared to projected market prices. Fuel supply agreements are valued at the time of acquisition based on the contract prices under the fuel supply agreement compared to projected market prices. The balances are presented net of accumulated amortization in the consolidated balance sheets. Amortization is recorded on a straight-line basis over the remaining term of the agreement.

(g) Investments accounted for by the equity method:

The Partnership has investments in entities that own power producing assets with the objective of generating cash flow. The equity method of accounting is applied to such investments in affiliates, which include joint ventures, partnerships, and limited liability companies because the ownership structure prevents the Partnership

from exercising a controlling influence over the operating and financial policies of the projects. The investments in partnerships and limited liability companies with 50% or less ownership, but greater than 5% ownership in which the Partnership does not have a controlling interest are accounted for under the equity method of accounting. The Partnership applies the equity method of accounting to investments in limited partnerships and limited liability companies with greater than 5% ownership because its influence over the investment's operating and financial policies is considered to be more than minor.

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

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

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

Investments in and the operating results of 50%-or-less owned entities not consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. The Partnership reviews its 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. The Partnership also reviews 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. The assessment as to whether any decline in value is other than temporary is based on the Partnership's 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. The Partnership generally considers its investments in its equity method investees to be strategic long-term investments. Therefore, the Partnership completes its 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.

(i) Goodwill:

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

Goodwill is not amortized and is tested for impairment, annually in the fourth quarter, or more frequently if events or changes in circumstances indicate that the asset might be impaired. The testing of goodwill provides the option to first perform a qualitative assessment ("step zero") to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If the Partnership determines that this is the case, the Partnership is required to perform a two-step goodwill impairment test, as described below, to identify potential goodwill impairment and measure the amount of goodwill impairment loss to be recognized for that reporting unit

(if any). If the Partnership determines that the fair value of a reporting unit is not less than its carrying amount, no impairment is recorded.

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

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

(j) Derivative financial instruments:

The Partnership uses derivative financial instruments in the form of foreign exchange forward contracts to manage the current and anticipated exposure to fluctuations in foreign currency exchange rates. The Partnership does not enter into derivative financial instruments for trading or speculative purposes. Certain derivative instruments qualify for a scope exception to fair value accounting because they are considered normal purchases or normal sales in the ordinary course of conducting business. This exception applies when the Partnership has the ability to, and it is probable that the Partnership will deliver or take delivery of the underlying physical commodity.

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

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

(k) Income taxes:

Income tax expense includes the current tax obligation or benefit and change in deferred income tax asset or liability for the period. The Partnership uses the asset and liability method of accounting for deferred income taxes and records deferred income taxes for all significant temporary differences. Income tax benefits associated with uncertain tax positions are recognized when the Partnership determines that it is more-likely-than-not that the tax position will be ultimately sustained. Refer to Note 14 for more information.

(l) Revenue recognition:

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

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

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

Steam —Steam revenue payments under the PPAs are recognized upon transmission to the customer. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in the Partnership's "Other" line of the consolidated statements of operations.

(m) Power purchase arrangements containing a lease:

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

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

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

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

The local currency is the functional currency of the Partnership's U.S. and Canadian projects. The Partnership's reporting currency is the U.S. dollar. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted-average rates of exchange for the period. The resulting currency translation adjustments are not included in the determination of the Partnership's statements of operations for the period, but are accumulated and reported as a separate component of partner's equity until sale of the net investment in the project takes place. Foreign currency transaction gains or losses are reported within foreign exchange (gain) loss in the Partnership's statements of operations.

(o) Asset retirement obligations:

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

(p) Concentration of credit risk:

The financial instruments that potentially expose the Partnership to credit risk consist primarily of cash and cash equivalents, derivative instruments and accounts receivable. Cash is held by major financial institutions that are also counterparties to the Partnership's derivative instruments. The Partnership has long-term agreements to sell electricity, gas and steam to public utilities and corporations. The Partnership has exposure to trends within the energy industry, including declines in the creditworthiness of customers. The Partnership does not normally require collateral or other security to support energy-related accounts receivable. The Partnership does not believe there is

significant credit risk associated with accounts receivable due to the credit worthiness and payment history of customers. See Note 17, *Segment and geographic information*, for a further discussion of customer concentrations.

(q) Use of estimates:

The preparation of financial statements requires the Partnership to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, the Partnership has made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment, valuation of goodwill, intangible assets and liabilities related to PPAs and fuel supply agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the fair value of financial instruments and derivatives, pension obligations, asset retirement obligations and the allocation of taxable income and losses. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and the Partnership's planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(r) Recently issued accounting standards:

Adopted

In July 2013, the FASB issued changes to the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. These changes require an entity to present an unrecognized tax benefit as a liability in the financial statements if (i) a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that 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 become effective for the Partnership on January 1, 2014. The adoption of these changes 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 into net income 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 become effective for the Partnership on January 1, 2014. The adoption of this standard did not have a material 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 become effective for the Partnership on

January 1, 2014. The adoption of these changes did not have a material impact on the consolidated financial statements.

On January 1, 2013, the Partnership 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.

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 the 2016 annual period. The Partnership is 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 the Partnership initiates 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. The Partnership is currently evaluating the potential impact of these changes on the consolidated financial statements.

3. Acquisitions and divestments

2014 Divestments

(a) Greeley

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

4. Changes in accumulated other comprehensive loss by component

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

	Year Ended December 31,	
	2014	2013
Foreign currency translation		
Balance at beginning of period	\$ (22.2)	\$ 12.6
Other comprehensive loss:		
Foreign currency translation adjustments(1)	(43.7)	(34.8)
Balance at end of period	<u>\$ (65.9)</u>	<u>\$ (22.2)</u>

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

5. Equity method investments in unconsolidated affiliates

The following tables summarize the Partnership's equity method investment in an unconsolidated affiliate:

Entity name	Percentage of Ownership as of December 31, 2014	Carrying value as of December 31.	
		2014	2013
Frederickson	50.2%	\$ 135.0	\$ 153.8

Equity in earnings of the Partnership's equity method investment was as follows:

Entity name	Year Ended December 31,	
	2014	2013
Frederickson	2.2	2.1
Distributions from an equity method investment	(21.1)	—
Deficit in earnings (loss) of equity method investments, net of distributions	\$ (18.9)	\$ 2.1

The following summarizes the financial position at December 31, 2014 and 2013, and operating results for the years ended December 31, 2014 and 2013, respectively, for the Partnership's proportional ownership interest in Fredrickson:

	2014	2013
Assets		
Current assets	\$ 1.8	\$ 11.0
Non-current assets	134.0	143.9
	<u>\$ 135.8</u>	<u>\$ 154.9</u>
Liabilities		
Current liabilities	\$ 0.3	\$ 0.6
Non-current liabilities	0.5	0.4
	<u>\$ 0.8</u>	<u>\$ 1.0</u>
Operating results		
Revenue	\$ 20.6	\$ 20.7
Project expenses	18.4	18.5
Project other expense	—	(0.1)
Project income	<u>\$ 2.2</u>	<u>\$ 2.1</u>

6. Inventory

Inventory consists of the following:

	December 31,	
	2014	2013
Parts and other consumables	\$ 10.0	\$ 9.7
Fuel	6.2	3.4
Total inventory	<u>\$ 16.2</u>	<u>\$ 13.1</u>

7. Property, plant and equipment

	December 31, 2014	December 31, 2013	Depreciable Lives
Land	\$ 4.0	\$ 4.2	
Office equipment, machinery and other	2.0	1.7	3 - 10 years
Asset retirement obligation	29.3	31.4	1 - 42 years
Plant in service	926.1	962.6	1 - 45 years
Construction in progress	—	5.5	
	<u>961.4</u>	<u>1,005.4</u>	
Less: accumulated depreciation	<u>(170.3)</u>	<u>(123.0)</u>	
	<u>\$ 791.1</u>	<u>\$ 882.4</u>	

Depreciation expense of \$55.3 million and \$57.9 million was recorded for the years ended December 31, 2014 and 2013, respectively.

8. Goodwill

The Partnership's goodwill balance was \$197.2 million and \$296.3 million as of December 31, 2014 and December 31, 2013, respectively. The Partnership recorded \$331.2 million of goodwill, which was pushed down from Atlantic Power in connection with its acquisition of the Partnership in 2011. The Partnership applies an accounting standard under which goodwill has an indefinite life and is not amortized. Goodwill is tested for impairments at least annually, or more frequently whenever an event or change in circumstances occurs that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The Partnership tests goodwill for impairment at the reporting unit level, which is at the project level and, the lowest level below the operating segments for which discrete financial information is available.

Based on a prolonged decline in the market capitalization of the Parent, the Partnership determined that it was appropriate to initiate an event-driven test of the remaining goodwill at its reporting units. The test was performed as of August 31, 2014.

As a result of the event-driven goodwill assessment, the Partnership 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 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. 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 and oil prices resulting from an abundance of shale gas. The forecasts for discounted cash flows also reflect a higher level of uncertainty for re-contracting at prices that were previously forecasted in 2011.

In addition, the Partnership performed its annual goodwill impairment test as of November 30, 2014. Of the nine remaining reporting units with goodwill recorded, only Williams Lake failed step 1 of the two-step test. However, no impairment was recorded because the implied fair value of its goodwill exceeded the carrying value of its goodwill. Under step 1 of the 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 its accounting policies for long-lived assets and goodwill impairment, the Partnership also performs 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, the Partnership performed a long-lived asset impairment test and a goodwill impairment test as of June 30, 2014. Based on the results of the 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 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, the Partnership 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. The Partnership performed step 2 of the goodwill

impairment test and impaired all of the project's goodwill because the carrying value of goodwill exceeded its implied fair value. As a result, Tunis, a component of the East segment, recorded a \$5.2 million goodwill impairment charge. 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 the assessment of the forecasted cash flows from re-contracting and other strategic outcomes.

The Partnership updated its 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.

The Partnership determines the fair value of its reporting units using an income approach with discounted cash flow ("DCF") models, as the Partnership believes 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 its long-lived asset recovery and step 1 and 2 goodwill impairment tests for its reporting units are generally based on approved reporting unit operating plans for years with contracted PPAs and historical relationships for estimates at the expiration of PPAs. All cash flow forecasts from DCF models utilized estimated plant output for determining assumptions around future generation and industry data forward power and fuel curves to estimate future power and fuel prices. The Partnership 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. The Partnership utilized the assistance of valuation experts to perform step 1 and step 2 of the quantitative impairment test for several of its 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 the reporting units may include macroeconomic factors that significantly differ from the assumptions in timing or degree, increased input costs such as higher fuel prices and maintenance costs, or lower power prices than incorporated in the long-term forecasts.

The following table details the changes in the carrying amount of goodwill by operating segment:

	East	West	Total
Balance at December 31, 2013	107.8	188.5	296.3
Impairment of goodwill	(23.1)	(73.9)	(97.0)
Translation adjustment	—	(2.1)	(2.1)
Balance at December 31, 2014	<u>\$ 84.7</u>	<u>\$ 112.5</u>	<u>\$ 197.2</u>

9 . Power purchase agreements and other intangible assets and liabilities

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

	December 31,	
	2014	2013
	Other Intangible Assets, Net	Other Intangible Assets, Net
	Power Purchase Agreements	Power Purchase Agreements
Gross balances	\$ 539.0	\$ 561.0
Less: accumulated amortization	(190.6)	(144.7)
Net carrying amount	\$ 348.4	\$ 416.3

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

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

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

	2014	2013
Power purchase agreements	\$ 56.6	\$ 58.4
Fuel supply agreements	(1.2)	(1.2)
Total amortization	\$ 55.4	\$ 57.2

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

Year Ended December 31,	Power Purchase Agreements	Fuel Supply Agreements
2015	\$ 52.8	\$ (1.2)
2016	52.8	(1.2)
2017	52.9	(1.2)
2018	45.1	(1.2)
2019	42.8	(1.2)

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

As of December 31, 2014 (in years)	Power Purchase Agreements	Fuel Supply Agreements
Weighted average remaining amortization period	8.0	8.0

10. Other long-term liabilities

Other long-term liabilities consist of the following:

	2014	2013
Asset retirement obligations	\$ 51.2	\$ 54.0
Deferred revenue	0.9	4.0
Other	1.7	1.2
	<u>\$ 53.8</u>	<u>\$ 59.2</u>

The Partnership recorded these retirement obligations as the Partnership is legally required to remove certain facilities at the end of their useful lives and restore the sites to their original condition. The following table represents the fair value of ARO at the date of acquisition along with the additions, reductions and accretion related to the ARO for the year ended December 31, 2014:

	2014
Asset retirement obligations beginning of year	\$ 54.0
Accretion of asset retirement obligations	1.4
Sale of Greeley	(2.0)
Translation adjustments	(2.2)
Asset retirement obligations, end of year	<u>\$ 51.2</u>

11. Long-term debt

Long-term debt consists of the following:

	December 31, 2014	December 31, 2013	Interest Rate
Recourse Debt:			
Senior secured term loan facility, due 2021	\$ 541.5	\$ —	LIBOR(1) plus 3.8%
Senior unsecured notes, due June 2036 (Cdn\$210.0)	181.0	197.4	5.95%
Senior unsecured notes, due July 2014 (2)	—	190.0	5.90%
Series A senior unsecured notes, due August 2015 (2)	—	150.0	5.87%
Series B senior unsecured notes, due August 2017 (2)	—	75.0	5.97%
Non-Recourse Debt:			
Other long-term debt	0.6	0.9	5.5%-6.7%
Less: current maturities	(5.6)	(190.2)	
Total long-term debt	<u>\$ 717.5</u>	<u>\$ 423.1</u>	

Current maturities consist of the following:

	December 31, 2014	December 31, 2013	Interest Rate
Current Maturities:			
Senior secured term loan facility, due 2021	\$ 5.4	\$ —	LIBOR(1) plus 3.8%
Senior unsecured notes, due July 2014	—	190.0	5.90%
Other short-term debt	0.2	0.2	5.5-6.7%
Total current maturities	<u>\$ 5.6</u>	<u>\$ 190.2</u>	

-
- (1) LIBOR cannot be less than 1.00%. On May 5, 2014 the Partnership entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for \$199.0 million notional amount (\$182.7 million at December 31, 2014) of the \$600.0 million (\$541.5 million at December 31, 2014) outstanding aggregate borrowings under the senior secured term loan facility. See Note 13, *Derivative instruments* for further details.
- (2) The Series A senior unsecured notes due August 2015 and Series B senior unsecured notes due August 2017 were retired on February 26, 2014 with a portion of the proceeds from the Senior Secured Term Loan Facilities described below.

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

2015	\$	5.6
2016		5.4
2017		5.4
2018		5.4
2019		5.4
Thereafter		695.9
	\$	<u>723.1</u>

Senior Secured Credit Facilities

On February 24, 2014, the Partnership entered into the Senior Secured Term Loan Facility, comprising of \$600 million in aggregate principal amount, and a new senior secured revolving credit facility (the "Revolving Credit Facility") with a capacity of \$210 million (collectively, the "Senior Secured Credit Facilities"). Borrowings under the Senior Secured Credit Facilities are available in U.S. dollars and Canadian dollars and bear interest at a rate equal to the Adjusted Eurodollar Rate (LIBOR), the Base Rate or the Canadian Prime Rate, each as defined in the credit agreement governing the Senior Secured Term Loan Facilities (the "Credit Agreement"), as applicable, plus an applicable margin between 2.75% and 3.75% that varies depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. The applicable margin for term loans bearing interest at the Adjusted Eurodollar Rate and the Base Rate is 3.75% and 2.75% respectively and was 3.75% at December 31, 2014. The Adjusted Eurodollar Rate cannot be less than 1.00% (1.00% at December 31, 2014). As further described in Note 13, the Partnership entered into interest rate swap agreements on May 5, 2014 to mitigate the exposure to changes in the Adjusted Eurodollar Rate for a portion of the Senior Secured Term Loan Facility.

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

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

The Partnership's existing Cdn\$210 million aggregate principal amount of 6.0% Medium Term Notes due June 23, 2036 (the "MTNs") prohibit the Partnership (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries) to secure indebtedness, unless the MTNs are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, the Partnership has granted an equal and ratable security 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 Term Loan Facilities, it will be required to offer each electing lender to prepay such lender's term loans under the Senior Secured Term Loan Facilities at a price equal to 101% of par. In addition, in the event that the Partnership elects to repay, prepay or refinance all or any portion of the term loan facilities within one year from the initial funding date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid or refinanced.

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

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

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

The Partnership used the proceeds from the Senior Secured Term Loan Facility under the Senior Secured Credit Facilities to:

- redeem in whole, at a price equal to par plus \$31.1 million of accrued interest and make-whole premiums (i) the \$150 million aggregate principal amount outstanding of 5.87% Senior Guaranteed

Notes, Series A, due 2015 (the “Series A Notes”) and the \$75 million aggregate principal amount outstanding of 5.97% Senior Guaranteed Notes, Series B, due 2017 (the “Series B Notes”) issued by Atlantic Power (US) GP, and (ii) the \$190 million aggregate principal amount outstanding of 5.9% Senior Notes due 2014 issued by Curtis Palmer LLC (the “Curtis Palmer Notes”);

- pay transaction costs and expenses of approximately \$40.7 million including banking, legal and consulting fees which were capitalized as deferred financing costs; and
- make a distribution to the Parent in the amount of \$122 million which was used by the Parent, in addition to cash on hand, 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.

Notes of the Partnership (Senior unsecured notes, due June 2036)

The Partnership has outstanding Cdn\$210.0 million (\$181.0 million as of December 31, 2014) aggregate principal amount of 6.0% senior unsecured notes, due June 2036 (MTNs). Interest on the MTNs is payable semi-annually at 6.0%. Pursuant to the terms of the MTNs, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. The MTNs are guaranteed by Atlantic Power Corporation and Atlantic Power Preferred Equity Ltd., an indirect, wholly-owned subsidiary acquired in connection with the acquisition of the Partnership.

Notes of Curtis Palmer LLC (Senior unsecured notes, due July 2014)

The Curtis Palmer Notes had \$190.0 million aggregate principal outstanding at December 31, 2013. Interest on the Curtis Palmer Notes was payable semi-annually at 5.90%. Pursuant to the terms of the Curtis Palmer Notes, the Partnership was required to meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. The Curtis Palmer Notes were guaranteed by the Partnership.

See Senior Secured Term Loan Facilities above for discussion of the retirement of the Curtis Palmer Notes in 2014.

Notes of Atlantic Power (US) GP (Series A and B senior unsecured notes, due August 2015 and 2017, respectively)

Atlantic Power (US) GP a subsidiary of the Partnership and, an indirect, wholly-owned subsidiary of Atlantic Power, had outstanding \$150.0 million aggregate principal amount of 5.87% senior guaranteed notes, Series A, due August 2015 (the “Series A Notes”). Interest on the Series A Notes was payable semi-annually at 5.87%. Atlantic Power (US) GP had also outstanding \$75.0 million aggregate principal amount of 5.97% senior guaranteed notes, Series B, due August 2017 (the “Series B Notes” and together with the Series A Notes, the “Notes”). Interest on the Series B Notes was payable semi-annually at 5.97%. Pursuant to the terms of the Series A Notes and the Series B Notes, the Partnership was required to meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership and Atlantic Power (US) GP. The Series A Notes and the Series B Notes were guaranteed by Atlantic Power, the Partnership, Curtis Palmer LLC and the existing and future guarantors of Atlantic Power’s Senior Notes, senior credit facility and refinancings thereof.

See New Senior Secured Term Loan Facilities above for discussion of the retirement of these Notes of Atlantic Power (US) GP in 2014.

12. Fair value of financial instruments

The estimated carrying values and fair values of the Partnership’s recorded financial instruments related to operations are as follows:

	December 31,			
	2014		2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	\$ 50.2	\$ 50.2	\$ 29.8	\$ 29.8
Derivative assets current	—	—	0.2	0.2
Derivative assets non-current	1.1	1.1	1.2	1.2
Derivative liabilities current	29.7	29.7	18.7	18.7
Derivative liabilities non-current	35.4	35.4	61.9	61.9
Long-term debt, including current portion	723.1	667.8	613.3	561.2

The Partnership's financial instruments that are recorded at fair value have been classified into levels using a fair value hierarchy.

The three levels of the fair value hierarchy are defined below:

Level 1—Unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date. Financial assets utilizing Level 1 inputs include active exchange-traded securities.

Level 2—Quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.

Level 3—Unobservable inputs from objective sources. These inputs may be based on entity-specific inputs. Level 3 inputs include all inputs that do not meet the requirements of Level 1 or Level 2.

The following represents the recurring measurements of fair value hierarchy of the Partnership's financial assets and liabilities that were recognized at fair value as of December 31, 2014 and December 31, 2013. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	December 31, 2014			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	\$ 50.2	\$ —	\$ —	\$ 50.2
Derivative instruments asset	—	1.1	—	1.1
Total	\$ 50.2	\$ 1.1	\$ —	\$ 51.3
Liabilities:				
Derivative instruments liability	\$ —	\$ 65.1	\$ —	\$ 65.1
Total	\$ —	\$ 65.1	\$ —	\$ 65.1

	December 31, 2013			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	\$ 29.8	\$ —	\$ —	\$ 29.8
Derivative instruments asset	—	1.4	—	1.4
Total	\$ 29.8	\$ 1.4	\$ —	\$ 31.2
Liabilities:				
Derivative instruments liability	\$ —	\$ 80.6	\$ —	\$ 80.6
Total	\$ —	\$ 80.6	\$ —	\$ 80.6

The fair values of the Partnership's derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment. The fair values of such financial instruments are classified within Level 2 of the fair value hierarchy. The Partnership uses best estimates to determine the fair value of commodity and derivative contracts the Partnership holds. 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.

The Partnership also adjusts the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on the Partnership's credit rating and the credit rating of the Partnership's counterparties. As of December 31, 2014, the credit valuation adjustments resulted in a \$5.3 million net increase (gain) in change in fair value of derivative instruments. As of December 31, 2013, the credit valuation adjustments resulted in an \$8.3 million net increase (gain) in change in fair value of derivative instruments.

The carrying amounts for cash and cash equivalents approximate fair value due to their short-term nature. The fair value of long-term debt was determined using quoted market prices, as well as discounting the remaining contractual cash flows using a rate at which the Partnership could issue debt with a similar maturity as of the balance sheet date.

13. Derivative instruments

The Partnership recognizes all derivative instruments on the balance sheet as either assets or liabilities and measures them at fair value each reporting period. For the Partnership's derivatives, the changes in the fair value are immediately recognized in earnings. The guidelines apply to the Partnership's gas purchase agreements and foreign exchange contracts.

Gas purchase agreements

On March 12, 2012, the Partnership discontinued the application of the normal purchase normal sales ("NPNS") exemption on gas purchase agreements at the Partnership's North Bay, Kapuskasing and Nipigon projects. On that date, the Partnership entered into an agreement with a third party that resulted in the gas purchase agreements no longer qualifying for the NPNS exemption. The agreements at North Bay and Kapuskasing expire on December 31, 2016. These gas purchase agreements are derivative financial instruments and are recorded in the balance sheets at fair value and the changes in their fair market value are recorded in the statements of operations.

In May 2012, the Nipigon project entered into a long-term contract for the purchase of natural gas beginning on January 1, 2013 and expiring on December 31, 2022. This contract is accounted for as a derivative financial instrument and is recorded in the consolidated balance sheets at fair value. Changes in the fair market value of the contract are recorded in the consolidated statements of operations.

Volume of forecasted transactions

The Partnership has entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, as of year ended December 31, 2014 and December 31, 2013:

	Units	December 31, 2014	December 31, 2013
Interest rate swaps	Interest (US\$)	4.5	—
Gas purchase agreements	Natural Gas (Gigajoules)	33.9	41.1
Foreign currency forwards	Cdn\$	—	34.9

Fair value of derivative instruments

The Partnership has elected to disclose derivative instrument assets and liabilities on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. The following table summarizes the fair value of the Partnership's derivative assets and liabilities:

	December 31, 2014	
	Derivative Assets	Derivative Liabilities
Derivative instruments:		
Interest rate swaps current	—	1.1
Interest rate swaps long-term	1.2	—
Gas purchase agreements current	—	28.6
Gas purchase agreements long-term	—	35.5
Total derivative instruments	\$ 1.2	\$ 65.2

	December 31, 2013	
	Derivative Assets	Derivative Liabilities
Derivative instruments:		
Foreign currency forward contracts current	0.5	0.7
Foreign currency forward contracts long-term	1.2	—
Gas purchase agreements current	0.2	18.4
Gas purchase agreements long-term	—	62.0
Total derivative instruments	\$ 1.9	\$ 81.1

Impact of derivative instruments on the consolidated statements of operations

The following table summarizes realized (gains) and losses for derivative instruments:

	Classification of (gain) loss recognized in income	Year ended December 31,	
		2014	2013
Gas purchase agreements	Fuel	\$ 52.4	\$ 56.5
Interest rate swaps	Interest, net	0.9	—
Foreign currency forwards	Foreign exchange gain	0.5	(14.4)

The following table summarizes the unrealized gains and (losses) resulting from changes in the fair value of derivative financial instruments:

	Classification of (gain) loss recognized in income	Year ended December 31,	
		2014	2013
Gas purchase agreements	Change in fair value of derivatives	\$ (10.5)	\$ 19.2
Interest rate swaps	Change in fair value of derivatives	0.1	—
Foreign currency forwards	Foreign exchange loss	1.1	10.7

14. Income taxes

	Year ended December 31	
	2014	2013
Current income tax expense (benefit)	\$ 3.7	\$ 5.6
Deferred tax (benefit)	(12.3)	(15.9)
Total income tax (benefit), net	\$ (8.6)	\$ (10.3)

The following is a reconciliation of income taxes calculated at the Canadian enacted statutory rate of 26.0% at December 31, 2014 and 2013, to the provision for income taxes in the consolidated statements of operations:

	Year ended December 31,	
	2014	2013
Computed income taxes at Canadian statutory rate	\$ (29.0)	\$ (8.0)
Decreases resulting from:		
Operating countries with different income tax rates	(11.9)	(4.6)
	\$ (40.9)	\$ (12.6)
Change in valuation allowance	18.0	3.9
	(22.9)	(8.7)
Dividend withholding tax and other cash taxes	(0.2)	0.7
Foreign exchange	(5.0)	(5.2)
Changes in tax rates	0.8	0.8
Changes in estimates of tax basis of equity method investments	—	(0.4)
Capital loss recognized on tax restructuring	(10.2)	—
Goodwill impairment	33.9	13.6
Other	(5.0)	(11.1)
	14.3	(1.6)
	\$ (8.6)	\$ (10.3)

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2014 and 2013 are presented below:

	2014	2013
Deferred tax assets:		
Loss carryforwards	\$ 75.5	\$ 57.3
Finance and share issuance costs	0.1	2.0
Disallowed interest carryforward	1.1	0.1
Derivative contracts	17.0	27.3
Other	4.3	3.6
Total deferred tax assets	98.0	90.3
Valuation allowance	(24.1)	(6.1)
	73.9	84.2
Deferred tax liabilities:		
Intangible assets	(77.1)	(94.6)
Property, plant and equipment	(88.0)	(94.8)
Other long-term investments	0.1	(1.0)
Total deferred tax liabilities	(165.0)	(190.4)
Net deferred tax liability	\$ (91.1)	\$ (106.2)

The following table summarizes the net deferred tax position as of December 31, 2013 and 2012:

	2014	2013
Long-term deferred tax liabilities	\$ (91.1)	\$ (106.2)
Net deferred tax liability	\$ (91.1)	\$ (106.2)

As of December 31, 2014, the Partnership has recorded a valuation allowance of \$24.1 million. This amount is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards. In assessing the recoverability of the Partnership's deferred tax assets, the Partnership considers whether it is more likely than not that some portion or the entire deferred tax asset will be realized. The ultimate realization of the deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

Tax benefits related to uncertain tax positions taken or expected to be taken on a tax return are recorded when such benefits meet a more likely than not threshold. Otherwise, these tax benefits are recorded when a tax position has been effectively settled, which means that the statute of limitation has expired or the appropriate taxing authority has completed their examination even though the statute of limitations remains open. Interest and penalties related to uncertain tax positions are recognized as part of the provision for income taxes and are accrued beginning in the period that such interest and penalties would be applicable under relevant tax law until such time that the related tax benefits are recognized. As of December 31, 2014, the Partnership has not recorded any tax benefits related to uncertain tax positions.

As of December 31, 2014, the Partnership had the following net operating loss carryforwards that are scheduled to expire in the following years:

2027	\$	12.5
2028		60.3
2029		20.8
2030		21.5
2031		18.1
2032		7.4
2033		15.4
2034		19.0
	\$	<u>175.0</u>

15. Preferred shares issued by a subsidiary company

In 2007, a subsidiary 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 the 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 Atlantic Power Corporation 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 the Partnership will not pay any dividends on its common shares.

The subsidiary company paid aggregate dividends of \$11.6 million on the Series 1 Shares and the Series 2 Shares in 2014 as compared to \$12.6 million in 2013.

16. Discontinued operations

On March 6, 2014, the Partnership sold its outstanding membership interests in Greeley for approximately \$1.0 million and recorded a \$2.1 million non-cash gain on the sale related to the write-off of asset retirement obligations. Greeley is accounted for as a component of discontinued operations in the consolidated statements of operations for the years ended December 31, 2014 and 2013, respectively.

	December 31,	
	2014	2013
Revenue	\$ —	\$ 7.6
Income from discontinued operations	2.0	0.9
Income tax expense	—	—
Income from discontinued operations, net of tax	\$ 2.0	\$ 0.9

17. Segment and geographic information

The Partnership has three reportable segments: East, West and Un-allocated Corporate. The Partnership analyzes the performance of the operating segments based on Project Adjusted EBITDA which is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. The Partnership uses 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. The equity investments in unconsolidated affiliates are presented on a proportionally consolidated basis in Project Adjusted EBITDA and in the reconciliation of Project Adjusted EBITDA to project income (loss). Greeley, which is a component of the West segment, is included in the loss from discontinued operations line item in the table below. The Partnership has adjusted prior periods to reflect this reclassification. A reconciliation of Project Adjusted EBITDA to project income (loss) is included in the table below:

Year ended December 31, 2014	East	West	Un-allocated Corporate	Consolidated
Project revenues	\$ 266.1	\$ 175.2	\$ (0.1)	\$ 441.2
Segment assets	725.7	820.9	95.8	1,642.4
Goodwill	84.7	112.5	—	197.2
Capital expenditures	12.3	1.8	—	14.1
Project Adjusted EBITDA	\$ 99.9	\$ 76.2	\$ 0.3	\$ 176.4
Change in fair value of derivative instruments	(11.6)	—	1.2	(10.4)
Depreciation and amortization	57.3	63.2	0.1	120.6
Interest, net	6.2	—	—	6.2
Other project expense	32.7	74.0	—	106.7
Project income (loss)	15.3	(61.0)	(1.0)	(46.7)
Administration	—	—	0.4	0.4
Interest, net	—	—	69.0	69.0
Foreign exchange gain	—	—	(18.6)	(18.6)
Other income, net	—	—	16.0	16.0
Income (loss) from continuing operations before income taxes	15.3	(61.0)	(67.8)	(113.5)
Income tax benefit	—	—	(8.6)	(8.6)
Income (loss) from continuing operations	15.3	(61.0)	(59.2)	(104.9)
Loss from discontinued operations	—	2.0	—	2.0
Net income (loss)	\$ 15.3	\$ (63.0)	\$ (59.2)	\$ (102.9)

Year ended December 31, 2013	East	West	Un-allocated Corporate	Consolidated
Project revenues	\$ 257.5	\$ 182.3	\$ (1.3)	\$ 438.5
Segment assets	970.1	995.7	(98.8)	1,867.0
Goodwill	107.8	188.5	—	296.3
Capital expenditures	4.4	1.1	—	5.5
Project Adjusted EBITDA	\$ 89.0	\$ 73.7	\$ (10.7)	\$ 152.0
Change in fair value of derivative instruments	(19.2)	—	—	(19.2)
Depreciation and amortization	60.3	65.8	0.1	126.2
Interest, net	11.2	0.1	(2.2)	9.1
Other project expense (income)	32.8	4.2	(0.5)	36.5
Project income (loss)	3.9	3.6	(8.1)	(0.6)
Administration	—	—	0.4	0.4
Interest, net	—	—	25.4	25.4
Foreign exchange gain	—	—	(9.4)	(9.4)
Other income, net	—	—	13.9	13.9
Income (loss) before income taxes	3.9	3.6	(38.4)	(30.9)
Income tax benefit	—	—	(10.3)	(10.3)
Net income (loss)	\$ 3.9	\$ 3.6	\$ (28.1)	\$ (20.6)

The table below provides information, by country, about the operations for each of the years ended December 31, 2014 and 2013 and Property, Plant & Equipment as of December 31, 2014 and 2013, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

	Revenue		Property, Plant & Equipment, net	
	2014	2013	2014	2013
United States	\$ 242.9	\$ 230.2	\$ 381.7	\$ 399.5
Canada	198.3	200.7	409.4	482.9
Total	\$ 441.2	\$ 430.9	\$ 791.1	\$ 882.4

Ontario Electricity Financial Corp (“OEFEC”), San Diego Gas & Electric, and BC Hydro provided 25.8%, 15.1%, and 9.1%, respectively, of total consolidated revenues for the year ended December 31, 2014. OEFEC, San Diego Gas & Electric and BC Hydro provided for 34.9%, 18.1%, and 12.7% of total consolidated revenues for the year ended December 31, 2013. OEFEC purchases electricity from the Calstock, Kapuskasing, Nipigon, North Bay and Tunis projects in the East segment. San Diego Gas & Electric purchases electricity from the Naval Station, Naval Training Center, and North Island projects in the West segment. BC Hydro purchases electricity from the Mamquam, Moresby Lake, and Williams Lake projects in the West segment.

18. Commitments and contingencies

Commitments

Fuel Supply and Transportation Commitments

The Partnership has entered into long-term contractual arrangements to procure fuel and transportation services for the projects. As of December 31, 2014, the Partnership’s commitments under such outstanding agreements are estimated as follows:

2015	\$	69.8
2016		63.8
2017		24.2
2018		16.7
2019		12.4
Thereafter		37.2
	\$	224.1

Contingencies

Other

From time to time, the Partnership and the projects are parties to disputes and litigation that arise in the normal course of business. The Partnership assesses the exposure to these matters and records estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on the Partnership's financial position or results of operations or have been reserved for as of December 31, 2014.

19. Related Parties

Transactions with Atlantic Power Corporation

Related party receivables and payables

The day-to-day management of the Partnership is the responsibility of Atlantic Power Corporation, the Partnership is charged for the salaries, pension, benefits and expenses of Atlantic Power and its affiliates attributable to the Partnership's operations on a cost recovery basis. The table below provides the amount of related party receivables and payables resulting from amounts charged by Atlantic Power as of December 31, 2014 and 2013, respectively:

	Year ended December 31,	
	2014	2013
Related party receivables	\$ 5.6	\$ 3.1
Related party payables	57.8	25.3