Atlantic Power Corporation

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Atlantic Power Corporation:

We have audited Atlantic Power Corporation's (the "Company") internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Atlantic Power Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Atlantic Power Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Atlantic Power Corporation and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive loss, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2016, and our report dated March 2, 2017 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

New York, New York

March 2, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Atlantic Power Corporation:

We have audited the accompanying consolidated balance sheets of Atlantic Power Corporation and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive loss, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2016. In connection with our audits of the consolidated financial statements, we also have audited financial statement schedules I to II in Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlantic Power Corporation and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Atlantic Power Corporation's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 2, 2017 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

New York, New York

March 2, 2017

ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(in millions of U.S. dollars)

	December 31, 2016	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$ 85.6	$ 72.4
Restricted cash	13.3	15.2
Accounts receivable	37.3	39.6
Current portion of derivative instruments asset (Notes 13 and 14)	4.0	—
Inventory (Note 6)	16.0	16.9
Prepayments	5.9	8.3
Other current assets	2.8	4.5
Total current assets	164.9	156.9
Property, plant, and equipment, net (Note 7)	733.2	777.7
Equity investments in unconsolidated affiliates (Note 5)	266.8	286.2
Power purchase agreements and intangible assets, net (Note 9)	246.2	308.9
Goodwill (Note 8)	36.0	134.5
Derivative instruments asset (Notes 13 and 14)	4.6	0.3
Other assets	5.1	6.7
Total assets	$ 1,456.8	$ 1,671.2
Liabilities		
Current liabilities:		
Accounts payable	$ 4.5	$ 6.9
Accrued interest	0.7	1.6
Other accrued liabilities	24.4	25.4
Current portion of long-term debt (Note 11)	111.9	15.8
Current portion of derivative instruments liability (Notes 13 and 14)	7.6	36.7
Other current liabilities	1.8	2.5
Total current liabilities	150.9	88.9
Long-term debt, net of unamortized discount and deferred financing costs (Note 11)	749.2	682.7
Convertible debentures, net of unamortized deferred financing costs (Note 12)	100.4	277.7
Derivative instruments liability (Notes 13 and 14)	21.3	20.8
Deferred income taxes (Note 15)	68.3	85.7
Power purchase and fuel supply agreement liabilities, net (Note 9)	25.3	27.0
Other long-term liabilities (Note 10)	55.5	53.2
Total liabilities	1,170.9	1,236.0
Equity		
Common shares, no par value, unlimited authorized shares; 114,649,888 and 122,153,082 issued and outstanding at December 31, 2016 and December 31, 2015	1,272.9	1,290.6
Accumulated other comprehensive loss (Note 4)	(148.5)	(139.3)
Retained deficit	(1,059.8)	(937.4)
Total Atlantic Power Corporation shareholders' equity	64.6	213.9
Preferred shares issued by a subsidiary company (Note 19)	221.3	221.3
Total equity	285.9	435.2
Total liabilities and equity	$ 1,456.8	$ 1,671.2

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

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

	Year Ended December 31,		
	2016	**2015**	**2014**
Project revenue:			
Energy sales	$ 184.2	$ 191.5	$ 236.9
Energy capacity revenue	141.9	149.3	161.3
Other	73.1	79.4	91.7
	399.2	420.2	489.9
Project expenses:			
Fuel	149.5	165.1	210.4
Operations and maintenance	105.2	103.5	109.0
Development	—	1.1	3.7
Depreciation and amortization	113.5	110.0	122.3
	368.2	379.7	445.4
Project other expenses:			
Change in fair value of derivative instruments (Notes 13 and 14)	37.9	15.4	6.8
Equity in earnings of unconsolidated affiliates (Note 5)	35.9	36.7	25.5
Gain on sale of equity investments (Note 3)	—	—	8.6
Interest, net	(9.2)	(8.2)	(17.7)
Impairment (Notes 8 and 9)	(85.9)	(127.8)	(106.6)
Other income, net (Note 3)	0.4	2.0	—
	(20.9)	(81.9)	(83.4)
Project income (loss)	10.1	(41.4)	(38.9)
Administrative and other expenses:			
Administration	22.6	29.4	37.9
Interest, net	106.0	107.1	146.7
Foreign exchange loss (gain) (Note 14)	13.9	(60.3)	(38.3)
Other income, net (Note 12)	(3.9)	(3.1)	(0.6)
	138.6	73.1	145.7
Loss from continuing operations before income taxes	(128.5)	(114.5)	(184.6)
Income tax benefit (Note 15)	(14.6)	(30.4)	(31.4)
Loss from continuing operations	(113.9)	(84.1)	(153.2)
Net income (loss) from discontinued operations, net of tax (Note 21)	—	19.5	(29.0)
Net loss	(113.9)	(64.6)	(182.2)
Net loss attributable to noncontrolling interests	—	(11.0)	(16.4)
Net income attributable to preferred shares dividends of a subsidiary company	8.5	8.8	11.6
Net loss attributable to Atlantic Power Corporation	$ (122.4)	$ (62.4)	$ (177.4)
Basic and diluted (loss) income per share: (Note 20)			
Loss from continuing operations attributable to Atlantic Power Corporation	$ (1.02)	$ (0.76)	$ (1.37)
Income (loss) from discontinued operations, net of tax	—	0.25	(0.10)
Net loss attributable to Atlantic Power Corporation	$ (1.02)	$ (0.51)	$ (1.47)
Weighted average number of common shares outstanding: (Note 20)			
Basic	119.5	121.9	120.7
Diluted	119.5	121.9	120.7
Dividends per common share:	$ —	$ 0.09	$ 0.29

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(in millions of U.S. dollars)

	Year Ended December 31,		
	2016	**2015**	**2014**
Net loss	$ (113.9)	$ (64.6)	$ (182.2)
Other comprehensive loss, net of tax:			
Unrealized loss on hedging activities	$ (0.2)	$ (0.6)	$ (1.0)
Net amount reclassified to earnings	0.7	0.7	0.9
Net unrealized gain (loss) on derivatives	0.5	0.1	(0.1)
Defined benefit plan, net of tax	(0.5)	1.6	(1.7)
Foreign currency translation adjustments	(9.2)	(72.8)	(44.1)
Other comprehensive loss, net of tax	(9.2)	(71.1)	(45.9)
Comprehensive loss	(123.1)	(135.7)	(228.1)
Less: Comprehensive income (loss) attributable to noncontrolling interests	8.5	(2.2)	(4.8)
Comprehensive loss attributable to Atlantic Power Corporation	$ (131.6)	$ (133.5)	$ (223.3)

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(in millions of U.S. dollars)

	Common Shares (Shares)	Common Shares (Amount)	Retained Deficit	Accumulated Other Comprehensive Income (loss)	Noncontrolling Interests	Preferred Shares of a Subsidiary Company	Total Shareholders' Equity
December 31, 2013	120.2	$ 1,286.1	$ (655.4)	$ (22.4)	$ 266.4	$ 221.3	$ 1,096.0
Net (loss) income	—	—	(177.4)	—	(16.4)	11.6	(182.2)
Common shares issued for LTIP	0.6	2.3	—	—	—	—	2.3
Common shares issued for DRIP	0.5	—	—	—	—	—	—
Dividends declared on common shares	—	—	(31.1)	—	—	—	(31.1)
Dividends paid to noncontrolling interests	—	—	—	—	(11.0)	—	(11.0)
Dividends declared on preferred shares of a subsidiary company	—	—	—	—	—	(11.6)	(11.6)
Unrealized loss on hedging activities, net of tax of $0.3 million	—	—	—	(0.1)	—	—	(0.1)
Foreign currency translation adjustments	—	—	—	(44.1)	—	—	(44.1)
Defined benefit plan, net of tax of $0.6 million	—	—	—	(1.7)	—	—	(1.7)
December 31, 2014	121.3	$ 1,288.4	$ (863.9)	$ (68.3)	$ 239.0	$ 221.3	$ 816.5
Net (loss) income	—	—	(62.4)	—	(11.0)	8.8	(64.6)
Common shares issued for LTIP	0.7	2.3	—	—	—	—	2.3
Common shares issued for DRIP	0.2	—	—	—	—	—	—
Common share repurchases	(0.1)	(0.1)	—	—	—	—	(0.1)
Dividends declared on common shares	—	—	(11.1)	—	—	—	(11.1)
Dividends paid to noncontrolling interests	—	—	—	—	(3.7)	—	(3.7)
Dividends declared on preferred shares of a subsidiary company	—	—	—	—	—	(8.8)	(8.8)
Derecognition of noncontrolling interests upon sale of subsidiaries	—	—	—	—	(224.3)	—	(224.3)
Unrealized gain on hedging activities, net of tax of $0.1 million	—	—	—	0.2	—	—	0.2
Foreign currency translation adjustments	—	—	—	(72.8)	—	—	(72.8)
Defined benefit plan, net of tax of $0.6 million	—	—	—	1.6	—	—	1.6
December 31, 2015	122.1	$ 1,290.6	$ (937.4)	$ (139.3)	$ —	$ 221.3	$ 435.2
Net loss	—	—	(122.4)	—	—	8.5	(113.9)
Common shares issued for LTIP	0.5	1.8	—	—	—	—	1.8
Dividends declared on preferred shares of a subsidiary company	—	—	—	—	—	(8.5)	(8.5)
Common share repurchases	(8.0)	(19.5)	—	—	—	—	(19.5)
Unrealized gain on hedging activities, net of tax of $0.2 million	—	—	—	0.5	—	—	0.5
Foreign currency translation adjustments	—	—	—	(9.2)	—	—	(9.2)
Defined benefit plan, net of tax of $0.2 million	—	—	—	(0.5)	—	—	(0.5)
December 31, 2016	114.6	$ 1,272.9	$ (1,059.8)	$ (148.5)	$ —	$ 221.3	$ 285.9

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of U.S. dollars)

	Years Ended December 31,		
	2016	2015	2014
Cash provided by operating activities:			
Net loss	$ (113.9)	$ (64.6)	$ (182.2)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation and amortization	113.5	120.3	162.6
Gain on sale of assets	0.2	(48.7)	(2.9)
Gain on sale of equity investments	—	—	(8.6)
Gain on purchase and cancellation of convertible debentures	(3.7)	(3.1)	—
Write off of deferred financing costs	32.8	9.0	—
Stock-based compensation expense	1.8	2.3	3.5
Long-lived asset and goodwill impairment charges	85.9	127.8	106.6
Equity in earnings from unconsolidated affiliates	(35.9)	(36.2)	(25.8)
Distributions from unconsolidated affiliates	55.3	58.5	76.2
Unrealized foreign exchange loss (gain)	13.8	(60.5)	(38.8)
Change in fair value of derivative instruments	(37.9)	(14.7)	8.7
Change in deferred income taxes	(17.5)	(3.5)	(15.7)
Change in other operating balances			
Accounts receivable	2.3	5.7	6.9
Inventory	0.9	2.4	(3.3)
Prepayments and other assets	17.0	11.9	21.1
Accounts payable	(0.2)	(8.9)	(4.1)
Accruals and other liabilities	(2.6)	(10.3)	(39.2)
Cash provided by operating activities	111.8	87.4	65.0
Cash (used in) provided by investing activities:			
Change in restricted cash	1.9	7.3	72.6
Proceeds from sale of assets and equity investments, net	—	326.3	9.5
Contribution to unconsolidated affiliate	—	(0.6)	—
Capitalized development costs	—	(0.8)	—
Reimbursement of costs for third-party construction project	4.8	—	—
Purchase of property, plant and equipment	(7.2)	(11.3)	(13.4)
Cash (used in) provided by investing activities	(0.5)	320.9	68.7
Cash used in financing activities:			
Proceeds from New Term Loan facility, net of discount	679.0	—	600.0
Common share repurchases	(19.5)	—	—
Repayment of corporate and project-level debt	(544.4)	(403.3)	(639.8)
Repayment of convertible debentures	(188.5)	(18.9)	(43.0)
Deferred financing costs	(16.2)	—	(39.0)
Dividends paid to common shareholders	—	(11.1)	(34.9)
Dividends paid to noncontrolling interests	—	(3.7)	(11.1)
Dividends paid to preferred shareholders	(8.5)	(8.8)	(14.6)
Cash used in financing activities	(98.1)	(445.8)	(182.4)
Net increase (decrease) in cash and cash equivalents	13.2	(37.5)	(48.7)
Cash and cash equivalents at beginning of period at discontinued operations	—	3.9	(3.9)
Cash and cash equivalents at beginning of period	72.4	106.0	158.6
Cash and cash equivalents at end of period	$ 85.6	$ 72.4	$ 106.0
Supplemental cash flow information			
Interest paid	$ 70.7	$ 100.0	$ 168.8
Income taxes paid, net	$ 3.5	$ 10.2	$ 3.8
Accruals for construction in progress	$ 1.2	$ 0.6	$ —

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

1. Nature of business

General

Atlantic Power owns and operates a diverse fleet of power generation assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term power purchase agreements (“PPAs”), which seek to minimize exposure to changes in commodity prices. As of December 31, 2016, our power generation projects had an aggregate gross electric generation capacity of approximately 2,138 megawatts (“MW”) in which our aggregate ownership interest is approximately 1,500 MW. Our current portfolio consists of interests in twenty-three power generation projects across nine states in the United States and two provinces in Canada. Nineteen of the projects are currently operational, totaling 1,975 MW on a gross capacity basis and 1,337 MW on a net ownership basis. The remaining four projects, all in Ontario, are not operational, three due to revised contractual arrangements with the offtaker and the other, Tunis, has a forward-starting 15-year contractual agreement that will commence between November 2017 and June 2019. Eighteen of our projects are majority-owned.

Atlantic Power is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the Toronto Stock Exchange under the symbol “ATP” and on the New York Stock Exchange under the symbol “AT.” Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 Canada and our headquarters is located at 3 Allied Drive, Suite 220, Dedham, Massachusetts 02026, USA.

2. Summary of significant accounting policies

(a) Principles of consolidation and basis of presentation:

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

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

(b) Cash and cash equivalents:

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

(c) Restricted cash:

Restricted cash represents cash and cash equivalents that are maintained by the projects or corporate to support payments for maintenance costs and meet project level and corporate contractual debt obligations. Restricted cash is classified as a current or long-term asset based on the timing and nature of when or how the cash is expected to be used or when the restrictions are expected to lapse.

(d) Accounts receivable:

Accounts Receivable are carried at cost. We periodically assesses the collectability of accounts receivable, considering factors such as specific evaluation of collectability, historical collection experience, the age of accounts receivable and other currently available evidence of the collectability, and record an allowance for doubtful accounts for the estimated uncollectible amount as appropriate.

(e) Deferred financing costs:

Deferred financing costs represent costs to obtain long-term financing and are amortized using the effective interest method over the term of the related debt, which ranges from 1 to 6 years. The carrying amount of deferred financing costs were recorded on the consolidated balance sheets as net of long-term debt and convertible debentures and was $17.8 million and $42.5 million at December 31, 2016 and 2015, respectively. Interest expense from the amortization of deferred finance costs for the years ended December 31, 2016, 2015, and 2014 was $40.8 million, $20.5 million, and $16.5 million, respectively.

(f) Inventory:

Inventory represents small parts and other consumables and fuel, the majority of which is consumed by our projects in provision of their services, and are valued at the lower of cost or net realizable value. Cost is the sum of the purchase price and incidental expenditures and charges incurred to bring the inventory to its existing condition or location. 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.

(g) 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. Significant additions or improvements extending asset lives or increasing generating capacity 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.

(h) Project development costs and capitalized interest:

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

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

(i) Other intangible assets:

Other intangible assets include PPAs and fuel supply agreements at our projects acquired as part of business combinations. 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.

(j) Investments accounted for by the equity method:

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

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

(k) Impairment of long-lived assets, 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 group 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 group. If the carrying amount of an asset group exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset group exceeds its fair value. Our asset groups have been determined to be at the plant level, which is the lowest level in which independent, separately identifiable cash flows have been identified.

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

(l) Goodwill:

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

Goodwill is not amortized and is tested for impairment, annually in the fourth quarter, or more frequently if events or changes in circumstances indicate that the asset might be impaired.

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

The second step is carried out when the carrying amount of a reporting unit exceeds its fair value, in which case, the implied fair value of the reporting unit's goodwill is compared with its carrying amount to measure the amount of the impairment loss, if any. The implied fair value of goodwill is determined in the same manner as the value of goodwill is determined in a business combination, using 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.

(m) Accounts payable and other accrued liabilities:

Accounts payable consists of amounts due to trade creditors related to our core business operations. These payables include amounts owed to vendors and suppliers for items such as fuel, maintenance, inventory and other raw materials. Other accrued liabilities include items such as income taxes, legal contingencies and employee-related costs including payroll, benefits and related taxes.

(n) Assets held for sale and discontinued operations:

For those businesses where we have committed to a plan to divest, each business is valued at the lower of its carrying amount or estimated fair value less cost to sell. If the carrying amount of the business exceeds its estimated fair value, an impairment loss is recognized. Fair value is estimated using accepted valuation techniques such as a discounted cash flow model, valuations performed by third parties, earnings multiples, or indicative bids, when available. A number of significant estimates and assumptions are involved in the application of these techniques, including the forecasting of markets and market share, sales volumes and prices, costs and expenses, and multiple other factors. We consider historical experience and all available information at the time the estimates are made; however, the fair value that is ultimately realized upon the divestiture of a business may differ from the estimated fair value reflected in the consolidated financial statements. Depreciation and amortization expense is not recorded on assets of a business to be divested once they are classified as held for sale. Businesses to be divested are classified in the consolidated financial statements as either discontinued operations or held for sale.

For businesses classified as discontinued operations, the balance sheet amounts and results of operations are reclassified from their historical presentation to assets and liabilities of operations held for sale on the consolidated balance sheet and to discontinued operations on the consolidated statements of operations, respectively, for all periods presented. The gains or losses associated with these divested businesses are recorded in discontinued operations on the consolidated statements of operations. Segment information does not include the assets or operating results of businesses classified as discontinued operations for all periods presented.

(o) Derivative financial instruments:

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

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

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

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

(p) Income taxes:

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

(q) Revenue recognition:

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

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

Capacity—Capacity payments under the PPAs are recognized as the amount billable under the PPA.

(r) Administrative expenses:

Administrative expenses include corporate and other expenses primarily for executive management, finance, legal, human resources and information systems, which are not directly allocable to our business segments.

(s) Power purchase arrangements containing a lease:

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

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

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

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

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

(u) Equity compensation plans:

The officers and certain other employees are eligible to participate in the Long-Term Incentive Plan ("LTIP"). Vested notional units are expected to be redeemed one-third in cash and two-thirds in shares of our common stock. Notional units granted that are expected to be redeemed in cash upon vesting are accounted for as liability awards. Notional units granted that are expected to be redeemed in common shares upon vesting are accounted for as equity awards. Unvested notional units are entitled to receive dividends equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested units are subject to forfeiture if the participant is not an employee at the vesting date.

We initially recognize compensation expense on the estimated number of notional units for which the requisite service is expected to be rendered. In 2016, we have estimated a weighted average forfeiture rate of 11% for the long-term incentive plan ("LTIP") granted in 2016. This estimate will be revisited if subsequent information indicates the actual number of notional units forfeited is likely to differ from previous estimates. Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and the fair value of the award at each balance sheet date for notional units accounted for as liability awards.

(v) Asset retirement obligations:

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

(w) Pensions:

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

(x) Business combinations:

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

(y) Concentration of credit risk:

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

(z) Use of estimates:

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

(aa) Recently adopted and issued accounting standards:

Accounting Standards Adopted in 2016

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 became effective for us for financial statements issued after December 15, 2016, and had no impact on the consolidated financial statements.

In January 2015, the FASB issued changes to the presentation of extraordinary items. Such items are defined as transactions or events that are both unusual in nature and infrequent in occurrence, and, currently, are required to be presented separately in an entity's income statement, net of income tax, after income from continuing operations. The changes eliminate the concept of an extraordinary item and, therefore, the presentation of such items will no longer be required. Notwithstanding this change, an entity will still be required to present and disclose a transaction or event that is both unusual in nature and infrequent in occurrence in the notes to the financial statements. These changes became effective for us on January 1, 2016. The adoption of these changes did not have an impact on the consolidated financial statements.

In February 2015, the FASB issued changes to the analysis that an entity must perform to determine whether it should consolidate certain types of legal entities. These changes (i) modify the evaluation of whether limited partnerships and similar legal entities are VIEs or voting interest entities, (ii) eliminate the presumption that a general partner should consolidate a limited partnership, (iii) affect the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships, and (iv) provide a scope exception from consolidation guidance for reporting entities with interests in legal entities that are required to comply with or operate in accordance with requirements that are similar to those in Rule 2a-7 of the Investment Company Act of 1940 for registered money market funds. These changes became effective for us on January 1, 2016, and had no impact on the consolidated financial statements.

In April 2015, the FASB issued changes to the presentation of debt issuance costs. The changes require that debt issuance costs be presented in an entity's balance sheet as a direct deduction from the carrying value of the related debt liability as opposed to a non-current asset on the consolidated balance sheet. The amortization of debt issuance costs remains unchanged. These changes became effective for us on January 1, 2016, and the adoption of these changes resulted in a decrease of approximately $17.8 million and $42.5 million at December 31, 2016 and 2015, respectively, to both deferred financing costs located in noncurrent assets, convertible debentures, and long-term debt on the accompanying consolidated balance sheets.

In September 2015, the FASB issued new guidance on adjustments to provisional amounts recognized in a business combination, which are currently recognized on a retrospective basis. Under the new requirements, adjustments will be recognized in the reporting period in which the adjustments are determined. The effects of changes in depreciation, amortization, or other income arising from changes to the provisional amounts, if any, are included in earnings of the reporting period in which the adjustments to the provisional amounts are determined. An entity is also required to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The new requirements became effective for us beginning January 1, 2016. We will apply this new guidance to any future business combinations.

Accounting Standards Not Yet Adopted

In January 2017, the FASB issued authoritative guidance, which removes the requirement to perform a hypothetical purchase price allocation to measure goodwill impairment. A goodwill impairment will now be the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. This guidance is effective for us for annual and interim periods beginning January 1, 2020, with early adoption permitted, and applied prospectively. We plan to adopt this guidance the earlier of an event-driven impairment test in 2017 or when we perform our annual goodwill impairment test in the fourth quarter of 2017. We cannot assess the impact on our financial statements because the determination will be made based on a fair value measurement at the time the test is conducted.

In November 2016, the FASB issued authoritative guidance to address diversity in practice of presenting changes in restricted cash on the statement of cash flows. The new guidance requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. The guidance is effective for fiscal years beginning after December 15, 2017, with early adoption permitted. The guidance will not have a material impact on the consolidated financial statements.

In October 2016, the FASB issued authoritative guidance, which amends existing guidance related to the recognition of current and deferred incomes taxes for intra-entity asset transfers. Under the new guidance, current and deferred income tax consequences of an intra-entity asset transfer, other than an intra-entity asset transfer of inventory, are now recognized when the transfer occurs. The guidance is effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2017 with early adoption permitted. We are currently evaluating the potential impact of the adoption on the consolidated financial statements.

In August 2016, the FASB issued authoritative guidance intended to clarify classification of specific cash flows that have aspects of more than one class of cash flows. As a result of this new guidance, entities should be applying specific GAAP in the following eight cash flow issues: Debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The guidance is effective for fiscal years beginning after December 15, 2017, with early adoption permitted. The guidance is not expected to have a material impact on the consolidated financial statements.

In March 2016, the FASB issued authoritative guidance intended to simplify and improve several aspects of the accounting for share-based payment transactions. The new guidance includes amendments to share-based accounting for income taxes, including adjustments to how excess tax benefits and a company's payments for tax withholdings should be classified in the statement of cash flows. This guidance is effective for annual and interim reporting periods beginning after December 15, 2016, with early adoption permitted. We are currently evaluating the potential impact on our financial position and results of operations upon adoption of this guidance.

In February 2016, the FASB issued authoritative guidance intended to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new guidance, lessees will be required to recognize a right-of-use asset and a lease liability, measured on a discounted basis, at the commencement date for all leases with terms greater than twelve months. Additionally, this guidance will require disclosures to help investors and other financial statement users to better understand the amount, timing, and uncertainty of cash flows arising from leases, including qualitative and quantitative requirements. The guidance should be applied under a modified retrospective transition approach for leases existing at the beginning of the earliest comparative period presented in the adoption-period financial statements. Any leases that expire before the initial application date will not require any accounting adjustment. This guidance is effective for annual reporting periods beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. We are currently evaluating the potential impact on our financial position and results of operations upon adoption of this guidance.

In November 2015, the FASB issued changes to the balance sheet classification of deferred taxes. These changes simplify the presentation of deferred income taxes by requiring all deferred income tax assets and liabilities, along with any related valuation allowance, to be classified as noncurrent in a classified balance sheet. The current requirement that deferred tax assets and liabilities of a tax-paying component of an entity be offset and presented as a single amount is not affected by these changes. The new guidance will be effective for us in fiscal years beginning after December 15, 2016 and is not expected to have an impact on the consolidated financial statements.

In July 2015, the FASB issued changes to the subsequent measurement of inventory. Currently, an entity is required to measure its inventory at the lower of cost or market, whereby market can be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. The changes require that inventory be measured at the lower of cost and net realizable value, thereby eliminating the use of the other two market methodologies. Net realizable value is defined as the estimated selling prices in the ordinary course of business less reasonably predictable costs of completion, disposal, and transportation. These changes become effective for us on January 1, 2017. We have determined that the adoption of these changes will not have an impact on the consolidated financial statements.

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity will recognize revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements will include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. Entities will generally be required to make more estimates and use more judgment under the new standard. The new requirements will be effective for us beginning January 1, 2018, and may be implemented either retrospectively for all periods presented, or as a cumulative-effect adjustment as of January 1, 2018. Early adoption is permitted, but not before January 1, 2017. Management is currently evaluating the potential impact of this new guidance on our consolidated financial statements. We have developed a project plan to assess the potential impact of the standard and have evaluated a sampling of our most significant contracts (PPAs). We have approximately 20 PPAs at our consolidated projects that require further analysis under this standard. Currently we recognize energy revenue upon transmission to the customer. Capacity revenue is recognized when billed as hours are made available under the terms of the relevant PPA. Our current policy appears to be in compliance with the new standard’s focus on when the customer obtains control of the goods or services. However, these agreements are complex and still require significant analysis prior to reaching a conclusion as to how the adoption of the standard will impact our financial position, results of operations and cash flows. We expect to utilize the cumulative-effect adjustment method upon adoption as of January 1, 2018.

3. Divestments

2015 Divestments

(a) Wind Projects

On March 31, 2015, Atlantic Power Transmission (“APT”), our wholly-owned, direct subsidiary, entered into a purchase agreement with TerraForm AP Acquisition Holdings, LLC (“TerraForm”), an affiliate of SunEdison, Inc., to sell our Wind Projects. On June 26, 2015, the sale was completed for aggregate cash proceeds of approximately $335 million after transaction fees, exclusive of transaction-related taxes. We recorded a $46.8 million gain on sale, which is included as a component of income from discontinued operations in the consolidated statements of operations for the year ended December 31, 2015.

Terraform acquired from APT, 100% of APT’s direct membership interests in a holding company formed to facilitate the sale, thereby acquiring our indirect interests in our portfolio of Wind Projects consisting of five operating wind projects in Idaho and Oklahoma and representing 521 MW net ownership: Goshen (12.5% economic interest), Idaho Wind (27.6% economic interest), Meadow Creek (100% economic interest); Rockland Wind Farm (50% economic interest, but consolidated on a 100% basis); and Canadian Hills (99% economic interest). As a result of the sale, we deconsolidated approximately $249 million of project debt (or approximately $274 million as adjusted for our proportional ownership of Rockland, Goshen North and Idaho Wind) and approximately $224 million of non-controlling interest related to tax equity interests at Canadian Hills and the minority ownership interests at Rockland and Canadian Hills.

The Wind Projects were designated as assets held for sale and discontinued operations on March 31, 2015, the date we established a firm commitment to a plan to sell the wind assets. Our determination to designate the Wind Projects as discontinued operations was based on the impact the sale will have on our operations and financial results and because the Wind Projects made up the entirety of our Wind Reportable Segment. We stopped depreciating the property, plant and equipment of the Wind Projects on the designation date.

(b) Frontier

On April 22, 2015, our indirect wholly-owned subsidiary, Ridgeline Energy LLC (‘‘Ridgeline’), closed a transaction with CRE-Frontier Solar California LLC (‘‘CRE’’), a subsidiary of Centaurus Renewable Energy LLC, whereby CRE agreed to purchase 100% of Ridgeline’s equity interests in Frontier Solar, LLC (‘‘Frontier’’), which is developing an approximately 20 MW solar electric generating facility in California, for net cash proceeds of $4.3 million. If Frontier achieves commercial operations and meets certain operating performance metrics, we could receive additional cash proceeds. We recorded a $2.3 million gain on sale related to the transaction in other income in the consolidated statements of operations for the year ended December 31, 2015. Frontier is not accounted for as a component of discontinued operations.

2014 Divestments

(a) Delta-Person

In December 2012, we and the other owners of Delta-Person, entered into a purchase and sale agreement with BHB Power, LLC and Public Service Company of New Mexico to sell the project for approximately $37.2 million including working capital adjustments. The sale of Delta-Person closed in July 2014 resulting in a gain on sale of approximately $8.6 million in the consolidated statement of operations for the year ended December 31, 2014. We received net cash proceeds in July 2014 for our ownership interest of approximately $7.2 million in the aggregate. Delta-Person is not accounted for as a component of discontinued operations.

(b) Greeley

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

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

4. Changes in accumulated other comprehensive loss by component

The changes in accumulated OCL by component are as follows:

	Year Ended December 31, 2016	2015	2014
Foreign currency translation			
Balance at beginning of period	$ (139.1)	$ (66.3)	$ (22.2)
Other comprehensive loss:			
Foreign currency translation adjustments[1]	(9.2)	(72.8)	(44.1)
Balance at end of period	$ (148.3)	$ (139.1)	$ (66.3)
Pension			
Balance at beginning of period	$ (0.4)	$ (2.1)	$ (0.4)
Other comprehensive loss:			
Unrecognized net actuarial gain (loss)	(0.7)	2.2	(2.3)
Tax benefit (expense)	0.2	(0.6)	0.6
Total Other comprehensive (loss) income before reclassifications, net of tax	(0.5)	1.6	(1.7)
Amortization of net actuarial loss	—	0.1	—
Tax benefit	—	—	—
Total amount reclassified from accumulated other comprehensive loss, net of tax	—	0.1	—
Total other comprehensive (loss) income	(0.5)	1.7	(1.7)
Balance at end of period	$ (0.9)	$ (0.4)	$ (2.1)
Cash flow hedges			
Balance at beginning of period	$ 0.2	$ 0.1	$ 0.2
Other comprehensive loss:			
Net change from periodic revaluations	(0.3)	(1.0)	(1.7)
Tax benefit	0.1	0.4	0.7
Total Other comprehensive loss before reclassifications, net of tax	(0.2)	(0.6)	(1.0)
Net amount reclassified to earnings:			
Interest rate swaps[2]	1.0	1.3	1.5
Tax expense	(0.3)	(0.6)	(0.6)
Total amount reclassified from accumulated other comprehensive loss, net of tax	0.7	0.7	0.9
Total other comprehensive (loss) income	0.5	0.1	(0.1)
Balance at end of period	$ 0.7	$ 0.2	$ 0.1

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

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

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

5. Equity method investments in unconsolidated affiliates

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

Entity name	Percentage of Ownership as of December 31, 2016	Carrying value as of December 31, 2016	Carrying value as of December 31, 2015
Frederickson[(1)]	50.2 %	$ 115.3	$ 124.7
Orlando Cogen, LP	50.0 %	7.3	8.4
Koma Kulshan Associates	49.8 %	5.0	5.4
Chambers Cogen, LP	40.0 %	127.6	135.7
Selkirk Cogen Partners, LP	17.7 %	11.6	12.0
Total		$ 266.8	$ 286.2

(1) We own 50.15% of Frederickson. However, we do not have financial control of the entity. The Frederickson entity is organized under a joint ownership agreement. Under the terms of that agreement, the two owner parties have joint control and substantive participating rights through the structure of its Owner's Committee. Each party has equal representation on this committee and unanimous consent is required over all significant decisions of the entity. These significant decisions include, but are not limited to (i) approval of the annual operating plan, annual operating budget, annual capital budget and five year forecasts, (ii) approval of all expenditures in excess of the approved budget, (iii) adoption of procedures intended to govern the operation and conduct of the facility, and (iv) entering into, amending, supplementing or terminating any project agreement. Disputes between the owners for these significant decisions are subject to independent arbitration. Accordingly, since we do not control the project, Frederickson is accounted for under the equity method of accounting.

Deficit in earnings of equity method investments, net of distributions, was as follows:

Entity name	Year Ended December 31, 2016	2015	2014
Frederickson	$ 2.2	$ 2.6	$ 2.2
Orlando Cogen, LP	27.8	27.0	18.6
Koma Kulshan Associates	0.8	0.4	0.9
Chambers Cogen, LP	5.5	6.5	7.0
Selkirk Cogen Partners, LP	(0.4)	0.2	(3.2)
Total	35.9	36.7	25.5
Distributions from equity method investments	(55.3)	(58.5)	(76.2)
Deficit in earnings of equity method investments, net of distributions	$ (19.4)	$ (21.8)	$ (50.7)

Distributions from equity method investments exceeded earnings of equity method investments for the years ended December 31, 2016, 2015 and 2014, respectively. Distributions from are equity method investments are typically based on project-level cash flows from operations or other non-GAAP metrics, whereas equity earnings include non-cash expenses such as depreciation and amortization or changes in the fair value of derivative financial instruments.

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

The following summarizes the financial position at December 31, 2016, 2015 and 2014, and operating results for the years ended December 31, 2016, 2015 and 2014, respectively, for our proportional ownership interest in equity method investments:

	2016	2015	2014
Assets			
Current assets			
Frederickson	$ 1.7	$ 1.8	$ 1.8
Orlando Cogen, LP	7.5	10.0	6.3
Koma Kulshan Associates	0.6	0.7	0.7
Chambers Cogen, LP	15.0	15.0	14.4
Selkirk Cogen Partners, LP	11.3	11.5	12.2
Non-current assets			
Frederickson	114.1	124.0	134.0
Orlando Cogen, LP	9.1	10.2	11.3
Koma Kulshan Associates	5.0	5.3	5.5
Chambers Cogen, LP	190.0	201.7	213.4
Selkirk Cogen Partners, LP	2.4	2.2	1.7
	$ 356.7	$ 382.4	$ 401.3
Liabilities			
Current liabilities			
Frederickson	$ 0.1	$ 0.7	$ 0.3
Orlando Cogen, LP	9.2	11.7	6.5
Koma Kulshan Associates	0.1	0.6	0.1
Chambers Cogen, LP	3.8	3.7	3.5
Selkirk Cogen Partners, LP	0.6	—	1.3
Non-current liabilities			
Frederickson	0.5	0.4	0.4
Orlando Cogen, LP	—	—	0.1
Koma Kulshan Associates	0.5	0.5	0.5
Chambers Cogen, LP	73.6	77.3	81.0
Selkirk Cogen Partners, LP	1.5	1.3	0.7
	$ 89.9	$ 96.2	$ 94.4

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

Operating results	2016	2015	2014
Revenue			
Frederickson	$ 20.7	$ 21.6	$ 20.6
Orlando Cogen, LP	54.6	54.1	50.5
Koma Kulshan Associates	1.9	1.5	1.9
Chambers Cogen, LP	44.7	48.0	54.8
Selkirk Cogen Partners, LP	7.9	11.6	41.6
Delta Person, LP	—	—	1.8
	129.8	136.8	171.2
Project expenses			
Frederickson	18.5	19.0	18.4
Orlando Cogen, LP	26.9	27.1	31.9
Koma Kulshan Associates	1.1	1.1	1.0
Chambers Cogen, LP	37.4	39.7	44.8
Selkirk Cogen Partners, LP	8.2	11.6	44.1
Delta Person, LP	—	—	1.7
	92.1	98.5	141.9
Project other expense			
Frederickson	—	—	—
Orlando Cogen, LP	—	—	—
Koma Kulshan Associates	—	—	—
Chambers Cogen, LP	(1.8)	(1.8)	(3.0)
Selkirk Cogen Partners, LP	—	0.2	(0.7)
Delta Person, LP	—	—	(0.1)
	(1.8)	(1.6)	(3.8)
Project income			
Frederickson	2.2	2.6	2.2
Orlando Cogen, LP	27.7	27.0	18.6
Koma Kulshan Associates	0.8	0.4	0.9
Chambers Cogen, LP	5.5	6.5	7.0
Selkirk Cogen Partners, LP	(0.3)	0.2	(3.2)
Delta Person, LP	—	—	—
	$ 35.9	$ 36.7	$ 25.5

6. Inventory

Inventory consists of the following:

	December 31, 2016	December 31, 2015
Parts and other consumables	$ 10.0	$ 9.3
Fuel	6.0	7.6
Total inventory	$ 16.0	$ 16.9

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

7. Property, plant and equipment, net

Property, plant and equipment, net consists of the following:

	December 31, 2016	December 31, 2015	Depreciable Lives
Land	$ 5.3	$ 5.2	
Office equipment, machinery and other	5.6	5.6	3 - 10 years
Leasehold improvements	2.2	—	7 - 15 years
Asset retirement obligation	27.7	27.4	1 - 43 years
Plant in service	981.1	975.8	1 - 45 years
	1,021.9	1,014.0	
Less accumulated depreciation	(288.7)	(236.3)	
Total property, plant and equipment, net	$ 733.2	$ 777.7	

Depreciation expense of $49.5 million, $59.0 million and $64.6 million was recorded for the years ended December 31, 2016, 2015 and 2014, respectively.

As described in Note 8, *Goodwill*, we recorded a $5.9 million and a $76.6 million long-lived asset impairment to property, plant and equipment in the years ended December 31, 2016 and 2015, respectively.

8. Goodwill

Our goodwill balance was $36.0 million and $134.5 million as of December 31, 2016 and December 31, 2015, respectively. We apply an accounting standard under which goodwill has an indefinite life and is not amortized. Goodwill is tested for impairments at least annually, or more frequently whenever an event or change in circumstances occurs that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We test goodwill for impairment at the reporting unit level, which is at the project level and, the lowest level below the operating segments for which discrete financial information is available.

In the third quarter of 2016, we performed an event-driven goodwill impairment test as of July 31, 2016. While declining power prices have been observed over the past two years, we identified a significant decrease in the long-term outlook for power prices in the regions where our reporting units operate in the third quarter of 2016. Because the estimated future cash flows of our reporting units are sensitive to fluctuations in forward power prices and these prices are the most impactful input in calculating a reporting unit's fair value, we determined that it was appropriate to perform an event-driven impairment test. For two of our reporting units (Morris and Nipigon) we performed a qualitative assessment and concluded that it was likely that the fair values significantly exceed the carrying values. These reporting units have aggregate goodwill of $6.9 million and have PPAs with significant remaining time before their expiration and are not significantly impacted by the decrease in the long-term outlook for power prices.

The other five of the reporting units tested (Curtis Palmer, Mamquam, North Bay, Kapuskasing and Moresby Lake) failed step 1 of our quantitative two-step test. Because five reporting units failed step 1 of the two-step goodwill impairment test, we identified a triggering event and initiated a test of the recoverability of their long-lived assets. The asset group for testing the long-lived assets for impairment is the same as the reporting unit for goodwill impairment testing purposes. In order to test the recoverability of the assets in the asset groups, we compared the carrying amount of the assets to estimated undiscounted future cash flows expected to be generated by the asset group. The carrying value of each asset group includes its recorded property, plant equipment, intangible assets related to PPAs and goodwill. Of the five asset groups tested, the North Bay and Kapuskasing asset groups (Canada segment) failed the recoverability test and we recorded property, plant and equipment impairment charges aggregating $5.9 million for the periods ended

September 30, 2016. For these asset groups, we estimated their fair value utilizing an income approach based on market participant assumptions. These assumptions include estimated cash flows under the remaining period of their respective PPAs.

Subsequent to recording long-lived asset impairments, we performed the step 2 goodwill impairment test and recorded a $50.2 million full impairment at the Mamquam reporting unit, a $15.4 million partial impairment at the Curtis Palmer reporting unit, a $6.5 million full impairment at the North Bay reporting unit, a $6.7 million full impairment at the Kapuskasing reporting unit and no impairment at the Moresby Lake reporting unit for a total goodwill impairment charge of $78.8 million for the period ended September 30, 2016. At the time of their acquisition in November 2011, the fair value of the assets acquired and liabilities assumed for the Mamquam and Curtis Palmer reporting units were valued assuming a merchant basis for the period subsequent to the expiration of the projects' original PPAs. The forecasted energy revenue on a merchant basis, in the respective markets in which those plants operate, was higher than the energy prices currently forecasted to be in effect subsequent to the expiration of the reporting unit's PPA. Power prices, in the respective markets in which those plants operate, have declined from 2011 and from the dates of our previous impairment assessments due to several factors including decreased demand, lower oil prices and lower natural gas prices resulting from an abundance of shale gas. Our forecasts for discounted cash flows also reflect a higher level of uncertainty for re-contracting at prices than were previously forecasted in 2011. The decline in forward power prices for British Columbia since our last goodwill impairment performed as of November 30, 2015, in particular, had a significant impact on the estimated discounted cash flows of our Mamquam reporting unit and was the primary driver for its recorded goodwill impairment. British Columbia's peak demand outlook has declined primarily attributable to a reduction in forecasted liquefaction build and need in the region and the associated loss of power demand. The resulting drop in the peak demand reduces the amount of needed capacity and therefore the capacity prices also were reduced. Furthermore, the PPA at the Curtis Palmer reporting unit expires at the earlier of December 2027 or the provision of 10,000 GWh of generation. Based on Curtis Palmer's cumulative generation through the date of the goodwill impairment test, we anticipate the PPA expiring two years before December 2027. As a result, the discounted cash flow model for Curtis Palmer utilizes forward power prices for that two-year period that are substantially lower than the prices under the current PPA.

The long-lived asset and goodwill impairment charges were recorded in the third quarter of 2016 and not earlier in the fiscal year because we did not identify any triggering events that would have required an event-driven impairment assessment. While declining power prices have been observed over the past two years, the significant decrease in the long-term outlook for power prices in the regions where our reporting units operate identified in the third quarter of 2016 had the most significant impact to the key inputs to our long-term forecasted cash flow models. Additionally, the PPAs at our North Bay and Kapuskasing reporting units expire on December 31, 2017. As these projects approach the expiration date, the remaining estimated contracted future cash flows decrease.

In the fourth quarter of 2016, we performed our annual goodwill impairment test as of November 30, 2016. Of the total remaining reporting units with goodwill recorded, Curtis Palmer ($29.1 million of goodwill at December 31, 2016) and Nipigon ($3.6 million of goodwill at December 31, 2016) passed step 1 of the two-step test. The total fair value of these reporting units exceeded their carrying value by approximately $62.7 million or 45%. For our Morris reporting unit, we performed a qualitative assessment and concluded that it was likely that the fair value significantly exceeded the reporting unit's carrying value. The Morris reporting unit has goodwill of $3.3 million and has a PPA with significant remaining time before its expiration and is not significantly impacted by the decrease in the long-term outlook for power prices.

The Moresby Lake reporting units failed step 1 of the two-step test. Accordingly, we performed a step 2 analysis for Moresby Lake and, as a result, recorded a $1.2 million full impairment in the year ended December 31, 2016. Moresby Lake has substantial useful life beyond the expiration of its PPA in 2022. However, Moresby Lake's fair value is estimated using a discounted cash flow approach and is sensitive to changes in forward power prices. These forward prices have declined significantly over the past several years. Moresby failed step 1 in our event-driven impairment test at July 31, 2016, but recorded no impairment as its implied goodwill exceeded its recorded goodwill. The further decline in forward power prices since our event-driven test resulted in the full impairment recorded at November 30, 2016.

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

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

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

The following table is a rollforward of goodwill for the years ended December 31, 2016 and 2015:

Reporting unit	Segment	December 31, 2015	Impairment	Translation adjustment	December 31, 2016
Curtis Palmer	East U.S.	$ 44.5	$ (15.4)	$ —	$ 29.1
Morris	East U.S.	3.3	—	—	3.3
Kapuskasing	Canada	8.8	(6.7)	(2.1)	—
Mamquam	Canada	64.4	(50.2)	(14.2)	—
Moresby Lake	Canada	1.6	(1.2)	(0.4)	—
Nipigon	Canada	3.6	—	—	3.6
North Bay	Canada	8.3	(6.5)	(1.8)	—
		$ 134.5	$ (80.0)	$ (18.5)	$ 36.0

Reporting unit	Segment	December 31, 2014	Impairment	Translation adjustment	December 31, 2015
Curtis Palmer	East U.S.	$ 58.2	$ (13.7)	$ —	$ 44.5
Morris	East U.S.	3.3	—	—	3.3
Kapuskasing	Canada	8.8	—	—	8.8
Mamquam	Canada	64.4	—	—	64.4
Moresby Lake	Canada	1.6	—	—	1.6
Williams Lake	Canada	46.4	(35.6)	(10.8)	—
Calstock	Canada	2.6	(1.9)	(0.7)	—
Nipigon	Canada	3.6	—	—	3.6
North Bay	Canada	8.3	—	—	8.3
		$ 197.2	$ (51.2)	$ (11.5)	$ 134.5

9. PPAs and other intangible assets and liabilities

Other intangible assets and liabilities include PPAs, fuel supply agreements and capitalized development costs.

In December 2016, we entered into agreements to terminate our PPAs at North Bay and Kapuskasing originally scheduled to expire on December 31, 2017. As a result, we wrote off the remaining intangible assets related to these PPAs and recorded $12.7 million of accelerated amortization expense in the year ended December 31, 2016.

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

The following tables summarize the components of our intangible assets and other liabilities subject to amortization at December 31, 2016 and 2015:

Assets

	Other Intangible Assets, Net		
	Power Purchase Agreements	Development Costs	Total
Gross balances, December 31, 2016	$ 538.7	$ 13.0	$ 551.7
Less: accumulated amortization	(292.7)	(12.8)	(305.5)
Net carrying amounts, December 31, 2016	$ 246.0	$ 0.2	$ 246.2

	Other Intangible Assets, Net		
	Power Purchase Agreements	Development Costs	Total
Gross balances, December 31, 2015	$ 534.0	$ 12.9	$ 546.9
Less: accumulated amortization	(225.4)	(12.6)	(238.0)
Net carrying amounts, December 31, 2015	$ 308.6	$ 0.3	$ 308.9

Liabilities

	Power Purchase and Fuel Supply Agreement Liabilities, Net		
	Power Purchase Agreements	Fuel Supply Agreements	Total
Gross balances, December 31, 2016	$ (29.0)	$ (12.6)	$ (41.6)
Less: accumulated amortization	11.0	5.3	16.3
Net carrying amounts, December 31, 2016	$ (18.0)	$ (7.3)	$ (25.3)

	Power Purchase and Fuel Supply Agreement Liabilities, Net		
	Power Purchase Agreements	Fuel Supply Agreements	Total
Gross balances, December 31, 2015	$ (28.4)	$ (12.6)	$ (41.0)
Less: accumulated amortization	9.1	4.9	14.0
Net carrying amounts, December 31, 2015	$ (19.3)	$ (7.7)	$ (27.0)

The following table presents amortization expense of intangible assets for the years ended December 31, 2016, 2015 and 2014:

	2016	2015	2014
PPAs	$ 63.3	$ 51.3	$ 57.6
Fuel supply agreements	(0.4)	(1.2)	(1.2)
Total amortization	$ 62.9	$ 50.1	$ 56.4

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

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

Year Ended December 31,	Power Purchase Agreements	Fuel Supply Agreements
2017	$ 38.0	$ (0.4)
2018	36.9	(0.4)
2019	36.3	(0.4)
2020	25.5	(0.4)
2021	22.9	(0.4)

The following table presents the weighted average remaining amortization period related to our intangible assets as of December 31, 2016:

As of December 31, 2016	Power Purchase Agreements	Fuel Supply Agreements
(in years)		
Weighted average remaining amortization period	7.9	18.6

10. Other long-term liabilities

Other long-term liabilities consist of the following at December 31:

	2016	2015
Asset retirement obligations	$ 50.3	$ 48.5
Net pension liability	1.3	0.6
Deferred revenue	—	0.5
Accrued LTIP and director share units	1.7	1.1
Other	2.2	2.5
	$ 55.5	$ 53.2

The following table is a rollforward of asset retirement obligations for the years ended December 31:

	2016	2015
Asset retirement obligations beginning of year	$ 48.5	$ 51.2
Accretion of asset retirement obligations	1.2	1.1
Translation adjustments	0.6	(3.8)
Asset retirement obligations, end of year	$ 50.3	$ 48.5

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

11. Long-term debt

Long-term debt consists of the following:

	December 31, 2016	December 31, 2015	Interest Rate
Recourse Debt:			
Senior Secured Term Loan facility, due 2021	$ —	$ 473.2	LIBOR[1] plus 3.75 %
New Term Loan facility, due 2023[2]	639.9	—	LIBOR[1] plus 5.00 %
Senior unsecured notes, due June 2036 (Cdn$210.0)	156.4	151.7	5.95 %
Non-Recourse Debt:			
Epsilon Power Partners term facility, due 2019	13.5	19.5	LIBOR[3] plus 3.125 %
Cadillac term loan, due 2025	27.0	29.5	LIBOR plus 1.37 %
Piedmont term loan, due 2018	56.6	59.0	LIBOR[3] plus 3.75 %
Other long-term debt	0.2	0.4	5.50 % - 6.70 %
Less: unamortized discount	(17.2)	—	
Less: unamortized deferred financing costs	(15.3)	(34.8)	
Less: current maturities	(111.9)	(15.8)	
Total long-term debt	$ 749.2	$ 682.7	

Current maturities consist of the following:

	December 31, 2016	December 31, 2015	Interest Rate
Current Maturities:			
Senior Secured Term Loan facility, due 2021	$ —	$ 4.7	LIBOR[1] plus 3.75 %
New Term Loan facility, due 2023[2]	100.0	—	LIBOR[1] plus 5.00 %
Epsilon Power Partners term facility, due 2019	6.2	6.0	LIBORplus 3.125 %
Cadillac term loan, due 2025	3.0	2.5	LIBOR[3] plus 1.37 %
Piedmont term loan, due 2018	2.5	2.4	LIBOR[3] plus 3.75 %
Other short-term debt	0.2	0.2	5.50 % - 6.70 %
Total current maturities	$ 111.9	$ 15.8	

(1) LIBOR cannot be less than 1.00%. We have entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $422.7 million of the $639.9 million outstanding aggregate borrowings under our New Term Loan facility at December 31, 2016. See Note 14, *Accounting for derivative instruments and hedging activities* for further details.

(2) On a quarterly basis, we make a cash sweep payment to fund the principal balance, based on terms as defined in the credit agreement and disclosed below. The portion of the New Term Loan facility classified as current is based on principal payments required to reduce the aggregate principal amount of New Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule.

(3) We have entered into interest rate swap agreements to economically fix our exposure to changes in interest rates for this non-recourse debt. See Note 14, *Accounting for derivative instruments and hedging activities*, for further details.

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

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

2017	$ 111.9
2018	153.4
2019	68.9
2020	108.1
2021	82.7
Thereafter	368.6
	$ 893.6

New Credit Facilities

On April 13, 2016, APLP Holdings Limited Partnership ("APLP Holdings"), our wholly-owned subsidiary, entered into new Senior Secured Credit Facilities, comprising $700 million in aggregate principal amount of Senior Secured Term Loan facilities (the "New Term Loans") and $200 million in aggregate principal amount of senior secured revolving credit facilities (the "New Revolver" and together with the New Term Loans, the "New Credit Facilities"). On the same date, $700 million was drawn under the New Term Loan, bearing interest at the Adjusted Eurodollar Rate plus the applicable margin of 5.00%, and letters of credit in an aggregate face amount of $105.8 million ($81.5 million at December 31, 2016) were issued (but not drawn) pursuant to the revolving commitments under the New Revolver and used (i) to fund a debt service reserve in an amount equivalent to six months of debt service (approximately $25.3 million), and (ii) to support contractual credit support obligations of APLP Holdings and its subsidiaries and of certain other affiliates of the Company. The New Revolver matures in April 2021 and the New Term Loans mature in April 2023. We received $679.0 million in proceeds after an original issue discount of 3% ($21.0 million).

We have used the $679.0 million proceeds from the New Term Loans to:

- redeem in whole, at a price equal to par plus accrued interest, Atlantic Power Limited Partnership's ("APLP") existing Senior Secured Term Loan, maturing in February 2021, in an aggregate principal amount outstanding of $447.9 million (see "Senior Secured Credit Facilities" below);
- redeem in whole, at a price equal to par plus accrued interest (i) our outstanding Cdn$67.2 million 6.25% Convertible Unsecured Subordinated Debentures, Series A, maturing in March 2017 (the "Series A Debentures") and (ii) our outstanding Cdn$75.8 million 5.60% Convertible Unsecured Subordinated Debentures, Series B, maturing in June 2017 (the "Series B Debentures") (total US$ equivalent of $110.7 million);
- redeem, at a price equal to $965 per $1,000 principal amount plus accrued interest, $62.7 million of our 5.75% Convertible Unsecured Subordinated Debentures, Series C, maturing on June 30, 2019; and
- pay transaction costs and expenses of approximately $14.6 million.

We may use the remaining proceeds for any corporate purpose including additional common share repurchases.

We accounted for the redemption of the Senior Secured Credit Facilities as an extinguishment of debt and wrote off $30.2 million of deferred financing costs to interest expense in the year ended December 31, 2016.

Borrowings under the New Credit Facilities are available in U.S. dollars and Canadian dollars and bear interest at a rate equal to the Adjusted Eurodollar Rate, the Base Rate or the Canadian Prime Rate as applicable, plus an applicable margin between 4.00% and 5.00% that varies depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. The New Term Loans include a 3% original issue discount, and matures on April 12, 2023. The revolving commitments under the New Revolver terminate on April 12, 2021. Letters of credit are available to be issued under the New Revolver until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. In addition to paying interest on outstanding principal under the New Credit Facilities, APLP Holdings is required to pay a commitment fee of 0.75% times the unused commitments under the New Revolver.

The New Credit Facilities are secured by a pledge of the equity interests in APLP Holdings and certain of its subsidiaries, guaranties from certain of the subsidiaries of APLP Holdings (the "Subsidiary Guarantors"), a downstream guarantee from the Company, a limited recourse guaranty from Atlantic Power GP II, Inc., the entity that holds all of the equity interest in APLP Holdings, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of APLP Holdings and its subsidiaries (subject to certain exceptions), and certain other assets. The New Credit Facilities also have the benefit of 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 reserve requirement is maintained utilizing a letter of credit. APLP, a wholly-owned, indirect subsidiary of the Company, is a party to an existing indenture governing its Cdn$210 million aggregate principal amount of 5.95% Medium Term Notes due June 23, 2036 (the "MTNs") that prohibits APLP (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, APLP Holdings has granted an equal and ratable security interest in the collateral package securing the New Credit Facilities in favor of the trustee 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 negative covenants include a requirement that APLP Holdings and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 6.00:1.00 in 2016 to 4.25:1.00 from June 30, 2020, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 2.75:1.00 in 2016 to 4.00:1.00 from June 30, 2022. In addition, the Credit Agreement includes customary restrictions and limitations on APLP Holdings' 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 certain exceptions and other customary carve-outs and various thresholds. Specifically, APLP Holdings may be restricted from making dividend payments or other distributions to Atlantic Power Corporation, and APLP and its subsidiaries may be prohibited from making dividends or distributions to Atlantic Power Preferred Equity Limited shareholders in the event of a covenant default or if APLP Holdings fails to achieve a target principal amount on the new term loan that declines quarterly based on a predetermined specified schedule.

Under the Credit Agreement, if a Change of Control (as defined in the Credit Agreement) occurs, unless APLP Holdings elects to make a voluntary prepayment of the term loans under the New Credit Facilities, it will be required to offer each electing lender a prepayment of such lender's term loans under the New Credit Facilities at a price equal to 101% of par. In addition, in the event that APLP Holdings elects to repay, prepay, refinance or replace 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, refinanced or replaced.

The Credit Agreement also contains a mandatory amortization feature and other mandatory prepayment provisions, including prepayments:

- from the proceeds of asset sales (except from the sale proceeds of certain excluded projects), insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and
- with respect to excess cash flows, to be determined by using the greater of (i) 50% of the cash flow of APLP Holdings and its subsidiaries that remains after the application of funds, in accordance with a customary priority, to operations and maintenance expenses of APLP Holdings and its subsidiaries, debt

service on the New Credit Facilities and the MTNs, funding of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd., a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of New Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Failure to achieve the specified target principal amount for any quarter does not constitute a default by APLP Holdings.

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 APLP Holdings and its subsidiaries, bankruptcy, material judgments rendered against APLP Holdings or certain of its subsidiaries, certain ERISA or regulatory events, a Change of Control of APLP Holdings (solely with respect to the New Revolver), or defaults under certain guaranties and collateral documents securing the New Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

As of December 31, 2016, we had no amount outstanding and $81.5 million issued in letters of credit under our revolving credit facility.

Senior Secured Credit Facilities

As noted above in “New Credit Facilities”, the Company’s Senior Secured Credit Facilities were repaid on April 13, 2016. The redemption and extinguishment was recorded in the three months ended June 30, 2016.

Notes of the Partnership

The Partnership, a wholly-owned subsidiary acquired on November 5, 2011, has outstanding Cdn$210.0 million ($156.4 million as of December 31, 2016) aggregate principal amount of 5.95% senior unsecured notes, due June 2036 (MTNs). Interest on the MTNs is payable semi-annually at 5.95%. Pursuant to the terms of the MTNs, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. The MTNs are guaranteed by Atlantic Power Corporation and Atlantic Power Preferred Equity Ltd., an indirect, wholly-owned subsidiary acquired in connection with the acquisition of the Partnership.

Notes of Atlantic Power Corporation

On July 26, 2015, we redeemed all of our outstanding $310.9 million aggregate principal amount of 9.0% Senior Unsecured Notes due November 2018 (the “Notes”) with the cash proceeds received from the sale of the Wind Projects. The Notes were redeemed at a price equal to 104.5 percent of the principal amount of the Notes, plus accrued and unpaid interest to the redemption date. We paid $330.4 million to fund the full redemption of the Notes, which includes $14.0 million in make-whole premiums and $5.5 million in accrued interest. The make whole premiums, accrued interest and the $9.0 million of deferred financing costs related to the Notes were recorded in interest expense in the year ended December 31, 2015.

Non-Recourse Debt

Project-level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The loans have certain financial covenants that must be met in order to distribute available cash. At December 31, 2016, all of our projects, with the exception of Piedmont, were in compliance with the covenants contained in project-level debt. Projects that do not meet their debt service coverage ratios are limited from making distributions, but the debt is not callable or subject to acceleration under the terms of their debt agreements. We do not expect the Piedmont project to meet its debt service coverage ratio covenants or to make distributions before the project's debt maturity in 2018 at the earliest.

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

12. Convertible debentures

The following table provides details related to outstanding convertible debentures:

	December 31, 2016	December 31, 2015
6.25% Debentures due March 2017	$ —	$ 48.6
5.60% Debentures due June 2017	—	54.8
5.75% Debentures due June 2019	42.6	117.0
6.00% Debentures due December 2019 (Cdn $81.0 million)	60.3	65.0
Less: Unamortized deferred financing costs	(2.5)	(7.7)
Total convertible debentures	$ 100.4	$ 277.7

On December 29, 2015, we commenced a Normal Course Issuer Bid ("NCIB"), which expired on December 28, 2016. The actual amount of convertible debentures that could be purchased under the NCIB was approximately $28.5 million and was further limited to 10% of the public float of our convertible debentures. On April 13, 2016, we deposited a portion of the proceeds from the issuance of the New Credit Facilities, for the redemption in whole on May 13, 2016 at a price equal to par plus accrued interest (i) the outstanding Cdn$67.2 million 6.25% Debentures due March 2017 and (ii) the outstanding Cdn$75.8 million 5.60% Debentures due June 2017. On June 17, 2016, we commenced a substantial issuer bid ("SIB") to purchase for cancellation up to $65.0 million aggregate principal amount of our issued and outstanding 5.75% Series C Convertible Unsecured Subordinated Debentures maturing June 30, 2019. The offer expired on July 22, 2016. As a result of the NCIB, the SIB and the redemptions made with proceeds from the New Credit Facilities, we made payments of $188.5 million to redeem and cancel the 6.25% Debentures due March 2017 and the 5.60% Debentures due June 2017, in full, and the 5.75% Debentures due June 2019 and 6.00% Debentures due December 2019, in part.

As a result of these repurchases and cancellations, we recorded a gain of $3.7 million in the consolidated statement of operations for the year ended December 31, 2016. Additionally, we wrote off $2.7 million of deferred financing costs related to the convertible debentures which was recorded to interest expense for the year ended December 31, 2016.

On November 2, 2016, our Board of Directors approved a new NCIB for each series of our convertible unsecured subordinated debentures. Under the NCIB, our broker may purchase up to $4.3 million principal amount of the 5.75% convertible debentures due June 2019 and Cdn$8.1 million of the 6.00% convertible debentures due December 2019. The Board authorization permits us to repurchase convertible debentures through open market repurchases. The NCIB commenced on December 29, 2016 and will expire on December 28, 2017 or such earlier date as we complete our respective purchases pursuant to the NCIB.

The $42.6 million remaining 5.75% Debentures due June 2019 pay interest semi-annually on the last day of June and December of each year. They are convertible into our common shares at an initial conversion rate of 57.9710 common shares per $1,000 principal amount, representing a conversion price of $17.25 per common share. The $60.3 million (Cdn$81.0 million) remaining 6.00% Debentures due December 2019 pay interest semi-annually on the last day of June and December of each year and are convertible into our common shares at an initial conversion rate of 68.9655 common shares per Cdn$1,000 principal amount, representing a conversion price of Cdn$14.50 per common share.

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

13. Fair value of financial instruments

The estimated carrying values and fair values of our recorded financial instruments related to operations are as follows:

	December 31,			
	2016		2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 85.6	$ 85.6	$ 72.4	$ 72.4
Restricted cash	13.3	13.3	15.2	15.2
Derivative assets current	4.0	4.0	—	—
Derivative assets non-current	4.6	4.6	0.3	0.3
Derivative liabilities current	7.6	7.6	36.7	36.7
Derivative liabilities non-current	21.3	21.3	20.8	20.8
Long-term debt, including current portion	893.6	826.0	733.3	686.5
Convertible debentures	102.9	102.0	285.4	231.4

Our financial instruments that are recorded at fair value have been classified into levels using a fair value hierarchy.

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

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

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

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

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

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of December 31, 2016 and December 31, 2015. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	December 31, 2016			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 85.6	$ —	$ —	$ 85.6
Restricted cash	13.3	—	—	13.3
Derivative instruments asset	—	8.6	—	8.6
Total	$ 98.9	$ 8.6	$ —	$ 107.5
Liabilities:				
Derivative instruments liability	$ —	$ 28.9	$ —	$ 28.9
Total	$ —	$ 28.9	$ —	$ 28.9

	December 31, 2015			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 72.4	$ —	$ —	$ 72.4
Restricted cash	15.2	—	—	15.2
Derivative instruments asset	—	0.3	—	0.3
Total	$ 87.6	$ 0.3	$ —	$ 87.9
Liabilities:				
Derivative instruments liability	$ —	$ 57.5	$ —	$ 57.5
Total	$ —	$ 57.5	$ —	$ 57.5

The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment. The fair values of such financial instruments are classified within Level 2 of the fair value hierarchy. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk free interest rate.

We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. As of December 31, 2016, the credit valuation adjustments resulted in a $3.8 million net increase in fair value, which consists of a $0.3 million pre-tax gain in other comprehensive income and a $3.5 million gain in change in fair value of derivative instruments. As of December 31, 2015, the credit valuation adjustments resulted in a $3.8 million net increase in fair value, which consists of a $0.4 million pre-tax gain in other comprehensive income and a $3.4 million gain in change in fair value of derivative instruments.

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

14. Accounting for derivative instruments and hedging activities

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. We have one contract designated as a cash flow hedge, and we defer the effective portion of the change in fair value of the derivatives in accumulated other comprehensive income (loss), until the hedged transactions occur and are recognized in earnings (loss). The ineffective portion of a cash flow hedge is immediately recognized in earnings (loss). For our other derivatives that are not designated as cash flow hedges, the changes in the fair value are immediately recognized in earnings (loss). These guidelines apply to our natural gas swaps, interest rate swaps, and foreign exchange contracts.

Gas purchase and sale agreements

We have entered into various gas purchase and sale agreements for our North Bay, Kapuskasing and Nipigon projects that expire ranging from March 31, 2017 through December 31, 2022. These agreements do not qualify for the normal purchase normal sales ("NPNS") exemption and are accounted for as derivative financial instruments because we could not conclude that it is probable that these contracts will not settle net and will result in physical delivery.

These derivative financial instruments are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

We have entered into various natural gas sales and purchase agreements for approximately 1.3 million Mmbtu to effectively mitigate seasonal fluctuation of future natural gas price at Morris through March 2017. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2016. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

Natural gas swaps

Our strategy to mitigate future exposure to changes in natural gas prices at our projects consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

We have entered into various natural gas swaps to effectively fix the price of 4.1 million Mmbtu of future natural gas purchases at Orlando, which is approximately 95% of our share of the expected natural gas purchases at the project in 2017 and 12% in 2018. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2016. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

Interest rate swaps

APLP Holdings has entered into several interest rate swap agreements to mitigate its exposure to changes in interest at the Adjusted Eurodollar Rate for $422.7 million notional amount of the remaining $639.9 million aggregate principal amount of borrowings under the New Term Loans. These interest rate swap agreements at various dates through March 31, 2020. Borrowings under the $700.0 million New Term Loans bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 5.00%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00% resulting in a minimum of a 6.00% all-in rate on the Term Loan Facility. As a result of entering into the swap agreements, the all-in rate for $422.7 million of the New Term Loans cannot be less than 6.00%, if the Adjusted Eurodollar Rate is equal to or greater than 1.00%.

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converts the floating rate debt to a fixed interest rate 4.5% with an applicable margin of 3.75%, resulting in an all-in rate of 8.22%. The swap continues at the fixed rate of 4.5% until November 2030. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

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

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.0% through February 15, 2015, 6.1% from February 16, 2015 to February 15, 2019, 6.3% from February 16, 2019 to February 15, 2023, and 6.4% thereafter. The notional amount of the interest rate swap agreement matches the outstanding principal balance over the remaining life of Cadillac's debt. This swap agreement, which qualifies for and is designated as a cash flow hedge, is effective through June 2025 and the effective portion of the changes in the fair market value is recorded in accumulated other comprehensive loss.

Foreign currency forward contracts

From time to time, we use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as many of our projects generate cash flow in U.S. dollars and Canadian dollars.

Volume of forecasted transactions

We have entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for the NPNS exemption at December 31, 2016 and December 31, 2015:

	Units	December 31, 2016	December 31, 2015
Natural gas swaps	Natural Gas (Mmbtu)	4.9	2.8
Gas purchase agreements	Natural Gas (Gigajoules)	11.3	25.0
Interest rate swaps	Interest (US$)	506.9	302.3

Fair value of derivative instruments

We have elected to disclose derivative instrument assets and liabilities on a trade-by-trade basis and do not offset amounts at the counterparty master agreement level. The following table summarizes the fair value of our derivative assets and liabilities:

	December 31, 2016	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.8
Interest rate swaps long-term	—	2.0
Total derivative instruments designated as cash flow hedges	—	2.8
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	0.4	1.9
Interest rate swaps long-term	4.5	6.5
Natural gas swaps current	3.9	0.8
Natural gas swaps long-term	0.1	—
Gas purchase agreements current	—	4.5
Gas purchase agreements long-term	—	12.7
Total derivative instruments not designated as cash flow hedges	8.9	26.4
Total derivative instruments	$ 8.9	$ 29.2

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

	December 31, 2015	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 1.0
Interest rate swaps long-term	—	2.7
Total derivative instruments designated as cash flow hedges	—	3.7
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	—	2.0
Interest rate swaps long-term	0.3	7.8
Natural gas swaps current	—	5.0
Natural gas swaps long-term	—	—
Gas purchase agreements current	—	28.7
Gas purchase agreements long-term	—	10.3
Total derivative instruments not designated as cash flow hedges	0.3	53.8
Total derivative instruments	$ 0.3	$ 57.5

Accumulated other comprehensive income

The following table summarizes the changes in the accumulated other comprehensive income (loss) ("OCI") balance attributable to derivative financial instruments designated as a hedge, net of tax:

Year Ended December 31, 2016	Interest Rate Swaps
Accumulated OCI balance at January 1, 2016	$ 0.2
Change in fair value of cash flow hedges	(0.2)
Realized from OCI during the period	0.7
Accumulated OCI balance at December 31, 2016	$ 0.7
Settlements expected to be recognized from OCI in expense in the next 12 months, net of $0.4 million of tax	$ 0.8

Year Ended December 31, 2015	Interest Rate Swaps
Accumulated OCI balance at January 1, 2015	$ 0.1
Change in fair value of cash flow hedges	(0.6)
Realized from OCI during the period	0.7
Accumulated OCI balance at December 31, 2015	$ 0.2

For the year ended December 31, 2014	Interest Rate Swaps
Accumulated OCI balance at January 1, 2014	$ 0.2
Change in fair value of cash flow hedges	(1.0)
Realized from OCI during the period	0.9
Accumulated OCI balance at December 31, 2014	$ 0.1

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

Impact of derivative instruments on the consolidated statements of operations

The following table summarizes realized loss for derivative instruments not designated as cash flow hedges:

	Classification of loss recognized in income	Year Ended December 31, 2016	2015	2014
Gas purchase agreements	Fuel	$ 48.5	$ 47.3	$ 52.4
Natural gas swaps	Fuel	4.9	6.0	4.3
Interest rate swaps	Interest, net	3.9	3.8	6.1
Foreign currency forwards	Foreign exchange loss	—	—	0.5

The following table summarizes the unrealized gain (loss) resulting from changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

	Classification of gain (loss) recognized in income	Year ended December 31, 2016	2015	2014
Natural gas swaps	Change in fair value of derivatives	$ 9.0	$ 1.0	$ (3.3)
Gas purchase agreements	Change in fair value of derivatives	22.8	16.1	11.6
Interest rate swaps	Change in fair value of derivatives	6.1	(1.7)	(1.5)
		$ 37.9	$ 15.4	$ 6.8
Foreign currency forwards	Foreign exchange loss	$ —	$ —	$ (1.1)

15. Income tax benefit

The following table summarizes the current and deferred portions of the net income tax benefit:

	Year Ended December 31 2016	2015	2014
Current income tax expense	$ 2.9	$ 5.3	$ 3.8
Deferred income tax benefit	(17.5)	(35.7)	(35.2)
Total income tax benefit, net	$ (14.6)	$ (30.4)	$ (31.4)

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

The following is a reconciliation of the income taxes calculated at the Canadian enacted statutory rate of 26% for the years ended December 31, 2016, 2015 and 2014, respectively, to the provision for income taxes in the consolidated statements of operations:

	Year ended December 31,		
	2016	2015	2014
Loss from continuing operations before income taxes	$ (128.5)	$ (114.5)	$ (184.6)
Computed income taxes at 26% Canadian statutory rate	(33.4)	(29.8)	(47.5)
Decreases resulting from:			
Operating countries with different income tax rates	(2.9)	(4.9)	(19.2)
	(36.3)	(34.7)	(66.7)
Change in valuation allowance	10.8	6.6	40.5
	(25.5)	(28.1)	(26.2)
Dividend withholding tax and other cash taxes	(0.4)	1.1	0.8
Foreign exchange	6.9	(7.0)	(7.4)
Changes in tax rates	(1.5)	2.1	(5.8)
Production tax credits	—	(3.6)	(0.3)
Changes in estimates of tax basis of equity method investments	1.3	(6.3)	(4.1)
Capital gain on intercompany notes	(0.2)	2.1	—
Goodwill impairment	22.3	14.8	33.9
Capital loss recognized on tax restructuring	(18.0)	—	(10.2)
Intra-period allocations from the Wind projects	—	(5.0)	(15.8)
Other	0.5	(0.5)	3.7
	10.9	(2.3)	(5.2)
Income tax benefit	$ (14.6)	$ (30.4)	$ (31.4)
Effective income tax rate	(11)%	(27)%	(17)%

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2016 and 2015 are presented below:

	2016	2015
Deferred tax assets:		
Loss carryforwards	$ 226.2	$ 224.6
Capital loss carryforwards	33.9	13.8
Finance and share issuance costs	3.4	1.7
Tax credits	4.7	4.7
LTIP	4.0	3.9
Derivative contracts	4.7	15.1
Other long-term notes	0.5	5.2
Other	6.5	6.0
Total deferred tax assets	283.9	275.0
Valuation allowance	(186.0)	(175.2)
	97.9	99.8
Deferred tax liabilities:		
Intangible assets	(72.0)	(79.0)
Property, plant and equipment	(94.2)	(106.5)
Total deferred tax liabilities	(166.2)	(185.5)
Net deferred tax liability	$ (68.3)	$ (85.7)

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

The following table summarizes the net deferred tax position as of December 31, 2016 and 2015:

	2016	2015
Long-term deferred tax liabilities	$ (68.3)	$ (85.7)
Net deferred tax liability	$ (68.3)	$ (85.7)

As of December 31, 2016, we have recorded a valuation allowance of $186.0 million. This amount is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards. Some of these loss carryforwards may be subject to limitation on their use. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax 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, 2016, we have not recorded any tax benefits related to uncertain tax positions.

As of December 31, 2016, we had the following net operating loss carryforwards that are scheduled to expire in the following years:

2027	$ 43.2
2028	93.0
2029	70.8
2030	25.8
2031	13.4
2032	19.0
2033	137.7
2034	167.0
2035	17.0
2036	32.1
	$ 619.0

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

16. Equity compensation plans

Long-term incentive plan ("LTIP")

The following table summarizes the changes in outstanding LTIP notional units during the years ended December 31, 2016, 2015 and 2014:

	Units	Grant Date Weighted-Average Fair Value per Unit
Outstanding at December 31, 2013	766,988	$ 7.86
Granted	1,776,083	2.64
Additional shares from dividends	178,114	3.79
Forfeitures	(294,037)	6.68
Vested and redeemed	(983,894)	4.78
Outstanding at December 31, 2014	1,443,254	3.28
Granted	1,007,726	2.75
Additional shares from dividends	59,996	2.87
Forfeitures	(136,894)	3.75
Vested and redeemed	(1,075,681)	3.21
Outstanding at December 31, 2015	1,298,401	2.88
Granted	1,594,954	1.81
Vested and redeemed	(784,806)	2.83
Forfeitures	(7,431)	2.71
Outstanding at December 31, 2016	2,101,118	$ 2.08

The total grant date fair value of all outstanding notional units under the LTIP was $4.4 million, $3.7 million and $4.6 million for the years ended December 31, 2016, 2015 and 2014. The weighted average remaining vesting term for outstanding notional units was 1.8 years at December 31, 2016. Approximately $1.5 million of total unrecognized compensation expense is expected to be recognized over this time period. Compensation expense related to LTIP was $2.8 million, $3.1 million and $3.5 million for the years ended December 31, 2016, 2015 and 2014, respectively. Cash payments made for vested notional units were $0.5 million, $0.9 million and $0.7 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Transition Equity Participation Agreement

We also have 539,904 transition notional shares outstanding at December 31, 2016 under the Transition Equity Participation Agreement with James J. Moore, Jr. Fifty percent of the transition notional shares granted with respect to fiscal year 2015 will vest upon the four-year anniversary of the date of grant and the remaining portion will vest on or any time after the two-year anniversary of the grant if the weighted average Canadian dollar closing price of our common shares on the TSX for at least three consecutive calendar months has exceeded the market price per common share determined as of January 22, 2015 (Cdn$3.18) by at least 50%.

17. Employee benefit plans

Defined benefit pension plan

We sponsor and operate a defined benefit pension plan that is available to certain legacy employees of the Partnership. The Atlantic Power Services Canada LP Pension Plan (the "Plan") is maintained solely for certain eligible legacy Partnership participants. The Plan is a defined benefit pension plan that allows for employee contributions. We expect to contribute $0.2 million to the pension plan in 2017.

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

The net annual periodic pension cost related to the pension plan for the years ended December 31, 2016, 2015 and 2014 includes the following components:

	2016	2015	2014
Service cost benefits earned	$ 0.7	$ 0.9	$ 0.8
Interest cost on benefit obligation	0.7	0.7	0.7
Expected return on plan assets	(0.9)	(0.9)	(0.8)
Net period benefit cost	$ 0.5	$ 0.7	$ 0.7

A comparison of the pension benefit obligation and related plan assets for the pension plan at December 31 is as follows:

	2016	2015
Benefit obligation at January 1	$ (15.1)	$ (16.2)
Service cost	(0.7)	(0.9)
Interest cost	(0.7)	(0.7)
Actuarial (gain) loss	(0.5)	2.2
Employee contributions	(0.1)	(0.1)
Benefits paid	0.1	0.7
Foreign currency translation adjustment	(0.4)	(0.1)
Benefit obligation at December 31	(17.4)	(15.1)
Fair value of plan assets at January 1	$ 14.4	$ 13.6
Actual return on plan assets	0.7	1.0
Employer contributions	0.5	0.5
Employee contributions	0.1	0.1
Benefits paid	(0.1)	(0.7)
Foreign currency translation adjustment	0.5	(0.1)
Fair value of plan assets at December 31	16.1	14.4
Funded status at December 31-excess of obligation over assets	$ (1.3)	$ (0.7)

Amounts recognized in the balance sheet at December 31 were as follows:

	2016	2015
Non-current liabilities	$ 1.3	$ 0.6

Amounts recognized in accumulated OCL that have not yet been recognized as components of net periodic benefit cost were as follows, net of tax:

	2016	2015
Unrecognized loss	$ 0.5	$ 1.6

We estimate that there will be no amortization of net loss for the pension plan from accumulated OCI to net periodic cost over the next fiscal year.

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

The following table presents the balances of significant components of the pension plan:

	2016	2015
Projected benefit obligation	$ 17.4	$ 15.1
Accumulated benefit obligation	15.1	12.6
Fair value of plan assets	16.1	14.4

The market-related value of the pension plan's assets is the fair value of the assets. Plan assets are invested in a common collective trust which totaled $16.1 million and $14.4 million for the years ended December 31, 2016 and 2015, respectively.

We determine the level in the fair value hierarchy within which the fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety. The fair value of the common/collective trust is valued at a fair value which is equal to the sum of the market value of the fund's investments, and is categorized as Level 2. There are no investments categorized as Level 1 or 3.

The following table presents the significant assumptions used to calculate our benefit obligations:

	2016	2015
Weighted-Average Assumptions		
Discount rate	4.0 %	4.3 %
Rate of compensation increase	2.0 %	3.0 %

The following table presents the significant assumptions used to calculate our benefit expense:

	2016	2015	2014
Weighted-Average Assumptions			
Discount rate	4.3 %	4.0 %	5.0 %
Rate of return on plan assets	5.8 %	6.0 %	6.0 %
Rate of compensation increase	3.0 %	4.0 %	4.0 %

We use December 31 as the measurement date for the Plan, and we set the discount rate assumptions on an annual basis on the measurement date. This rate is determined by management based on information provided by our actuary. The discount rate assumptions reflect the current rate at which the associated liabilities could be effectively settled at the end of the year. The discount rate assumptions used to determine future pension obligations as of the year ended December 31, 2016, 2015 and 2014, were based on the CIA / Natcan curve, which was designed by the Canadian Institute of Actuaries and Natcan Investment Management to provide a means for sponsors of Canadian plans to value the liabilities of their postretirement benefit plans. The CIA / Natcan curve is a hypothetical yield curve represented by extrapolating the corporate AA-rated yield curve beyond 10 years using yields on provincial AA bonds with a spread added to the provincial AA yields to approximate the difference between corporate AA and provincial AA credit risk. The CIA / Natcan curve utilizes this approach because there are very few corporate bonds rated AA or above with maturities of 10 years or more in Canada.

We employ a balanced total return investment approach, whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, and the plan's funded status. Plan assets in the common collective trust are currently invested in a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across Canadian, U.S. and other international equities, as well as among growth, value and small and large capitalization stocks.

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

The pension plan assets weighted average allocations in the common collective trust were as follows:

	2016	2015
Canadian equity	30 %	29 %
U.S. equity	14 %	14 %
International equity	14 %	14 %
Canadian fixed income	39 %	40 %
International fixed income	3 %	3 %
	100 %	100 %

Our expected future benefit payments for each of the next five years and in the aggregate for the five years thereafter, are as follows in Cdn$:

	2016
2017	Cdn$ 0.3
2018	0.4
2019	0.5
2020	0.6
2021	0.7
2022-2025	4.9

In January 2017, we notified several employees whom are participants in the Plan of their termination, which is expected to be effective in March 2017. Because of the terminations, we expect to record a pre-tax curtailment gain of approximately $0.4 million in the three months ended March 31, 2017. We recorded $1.1 million of severance expense in the fourth quarter of 2016 for these employees and expect to record an additional $0.5 million of severance in 2017.

Defined Contribution Plans

We maintain a 401(k) retirement savings plan, registered retirement savings plan, and another defined contribution plan for the benefit of our eligible employees. Substantially all of our employees who meet certain service and age requirements are eligible to participate in these plans. Our plan documents provide that any matching contributions by us are discretionary. We have made or accrued matching contributions to these plans of $1.4 million, $1.3 million, and $2.5 million for the years ended December 31, 2016, 2015 and 2014, respectively.

18. Common shares

Stock Repurchase Program

In December 2015, our Board of Directors approved an NCIB for each series of our convertible unsecured subordinated debentures, our common shares and for each series of the preferred shares of Atlantic Power Preferred Equity Ltd (“APPEL”), our wholly-owned subsidiary. The Board authorization permitted the Company to repurchase stock through open market repurchases. The NCIB expired on December 28, 2016. For the year ended December 31, 2016, we repurchased a cumulative 8.0 million common shares at a total cost of $19.5 million. Repurchases and retirement of common shares are recorded to common shares on the consolidated balance sheets.

On December 29, 2016, we commenced a new NCIB that will expire on December 28, 2017 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the NCIBs. Under the new NCIB, we may purchase up to approximately 11.3 million common shares, or 10% of our public float.

Common Share Dividends

We paid dividends of Cdn$0.03 per outstanding share to our common stockholders during the first, second, third and fourth quarters of 2015.

On February 9, 2016, we announced the elimination of our common stock dividend, effective immediately. In conjunction with the elimination of the common stock dividend, our dividend reinvestment plan (the "Plan") also was eliminated. We filed a post-effective amendment to our registration statement on Form S-3 (Registration No. 333-194204) to deregister all of the Company's common shares that remain unissued under the Plan.

19. Preferred shares issued by a subsidiary company

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

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

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

The subsidiary company paid aggregate dividends of $8.5 million on the Series 1 Shares, Series 2 Shares and Series 3 in 2016 as compared to $8.8 million in 2015.

20. Basic and diluted loss per share

Basic loss per share is calculated by dividing net loss by the weighted average common shares outstanding during their respective period. Diluted earnings per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

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

Because we reported a loss for the years ended December 31, 2016, 2015 and 2014, diluted loss per share is equal to basic loss per share as the inclusion of potentially dilutive shares in the computation is anti-dilutive.

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the years ended December 31, 2016, 2015 and 2014:

	2016	2015	2014
Numerator:			
Loss from continuing operations attributable to Atlantic Power Corporation	$ (122.4)	$ (92.9)	$ (164.8)
Income (loss) from discontinued operations, net of tax	—	30.5	(12.6)
Net loss attributable to Atlantic Power Corporation	$ (122.4)	$ (62.4)	$ (177.4)
Denominator:			
Weighted average basic shares outstanding	119.5	121.9	120.7
Dilutive potential shares:			
Convertible debentures	13.1	22.7	27.7
LTIP notional units	0.1	0.2	0.3
Potentially dilutive shares	132.7	144.8	148.7
Diluted loss per share from continuing operations attributable to Atlantic Power Corporation	$ (1.02)	$ (0.76)	$ (1.37)
Diluted earnings (loss) per share from discontinued operations	—	0.25	(0.10)
Diluted loss per share attributable to Atlantic Power Corporation	$ (1.02)	$ (0.51)	$ (1.47)

The dilutive effect of our convertible debentures is calculated using the "if-converted method." Under the if-converted method, the debentures are assumed to be converted at the beginning of the period, and the resulting common shares are included in the denominator of the diluted EPS calculation for the entire period being presented. Interest expense, net of any income tax effects, would be added back to the numerator for purposes of the if-converted calculation. Potentially dilutive shares from convertible debentures and notional units have been excluded from fully diluted shares for the years ended December 31, 2016, 2015 and 2014, respectively, because their impact would be anti-dilutive.

21. Discontinued operations

On June 26, 2015, APT, our wholly-owned, direct subsidiary, sold our Wind Projects under a definitive agreement (the "Purchase Agreement") with TerraForm AP Acquisition Holdings, LLC ("TerraForm"), an affiliate of SunEdison, Inc. (an affiliate of TerraForm Power, Inc.). The sale was completed for aggregate cash proceeds of approximately $335 million after transaction fees, exclusive of transaction-related taxes. We recorded an approximate $46.8 million gain on sale, which is included as a component of income from discontinued operations in the consolidated statements of operations for the year ended December 31, 2015.

Terraform acquired from APT, 100% of APT's direct membership interests in a holding company formed to facilitate the sale, thereby acquiring our indirect interests in our portfolio of Wind Projects consisting of five operating wind projects in Idaho and Oklahoma and representing 521 MW net ownership: Goshen (12.5% economic interest), Idaho Wind (27.6% economic interest), Meadow Creek (100% economic interest); Rockland Wind Farm (50% economic interest, but consolidated on a 100% basis); and Canadian Hills (99% economic interest). As a result of the sale, we deconsolidated approximately $249 million of project debt (or approximately $274 million as adjusted for our proportional ownership of Rockland, Goshen North and Idaho Wind) and approximately $224 million of non-controlling interest related to tax equity interests at Canadian Hills and the minority ownership interests at Rockland and Canadian Hills.

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

The Wind Projects were designated as assets held for sale and discontinued operations on March 31, 2015, the date we established a firm commitment to a plan to sell the wind assets. Our determination to designate the Wind Projects as discontinued operations was based on the impact the sale would have on our operations and financial results and because the Wind Projects made up the entirety of our Wind reportable segment. We stopped depreciating the property, plant and equipment of the Wind Projects on the designation date.

On March 6, 2014, we sold our outstanding membership interests in Greeley for approximately $1.0 million and recorded a $2.1 million non-cash gain on the sale related to the write off of asset retirement obligations. Greeley is accounted for as a component of discontinued operations in the consolidated statements of operations for the years ended December 31, 2015, 2014, and 2013, respectively.

The following tables summarize the revenue, loss from operations, and income tax expense of the Wind Projects and Greeley for the years ended December 31, 2015 and 2014:

	2015	2014
Revenue	$ 34.8	$ 79.3
Project expenses:		
Fuel	—	—
Operations and maintenance	10.8	21.1
Depreciation and amortization	10.3	40.3
	21.1	61.4
Project other income (expense):		
Change in fair value of derivatives	(0.7)	(15.5)
Equity in earnings of unconsolidated affiliates	(0.5)	0.3
Interest expense, net	(6.7)	(14.2)
Gain on sale of asset	46.8	2.0
	38.9	(27.4)
Income (loss) from operations of discontinued businesses	52.6	(9.5)
Income tax expense	33.1	19.5
Income (loss) from operations of discontinued businesses, net of tax	19.5	(29.0)
Net loss attributable to noncontrolling interests of discontinued businesses	(11.0)	(16.4)
Income (loss) from operations of discontinued businesses, net of noncontrolling interests	$ 30.5	$ (12.6)

The following table summarizes the operating and investing cash flows of the Wind Projects for the years ended December 31, 2015 and 2014:

	December 31,	
	2015	2014
Cash provided by operating activities	$ 21.9	$ 48.3
Cash (used in) provided by investing activities	(12.8)	4.8

Basic and diluted loss per share related to income (loss) from discontinued operations for the Wind Projects and Greeley was $0.25 and ($0.10) for the years ended December 31, 2015 and 2014, respectively.

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

22. Segment and geographic information

We have four reportable segments: East U.S., West U.S., Canada and Un-Allocated Corporate. We revised our reportable business segments in the second quarter of 2015 as a result of significant project asset sales and in order to align our reportable business segments with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. Our financial results for the year ended December 31, 2014 have been presented to reflect these changes in operating segments. We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use Project Adjusted EBITDA to provide comparative information about segment performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. Our equity investments in unconsolidated affiliates are presented on a proportionally consolidated basis in Project Adjusted EBITDA and in the reconciliation of Project Adjusted EBITDA to project income (loss). Wind projects, which were components of the former Wind segment and Greeley, which was a component of the West U.S. segment, are excluded in the income (loss) from continuing operations line item in the table below. We have adjusted prior periods to reflect this reclassification.

A reconciliation of Project Adjusted EBITDA to net income (loss) from continuing operations to is included in the tables below:

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Year Ended December 31, 2016					
Project revenues	$ 134.5	$ 101.3	$ 162.5	$ 0.9	$ 399.2
Segment assets	754.2	313.6	291.8	97.2	1,456.8
Goodwill	32.4	—	3.6	—	36.0
Capital expenditures	6.2	—	0.9	0.1	7.2
Project Adjusted EBITDA	$ 92.4	$ 51.2	$ 58.8	$ (0.2)	$ 202.2
Change in fair value of derivative instruments	(9.2)	—	(25.5)	(3.2)	(37.9)
Depreciation and amortization	44.1	39.4	49.5	0.5	133.5
Interest, net	10.9	—	—	—	10.9
Impairment	15.4	—	70.5	—	85.9
Other project expense	—	—	—	(0.3)	(0.3)
Project income (loss)	31.2	11.8	(35.7)	2.8	10.1
Administration	—	—	—	22.6	22.6
Interest, net	—	—	—	106.0	106.0
Foreign exchange loss	—	—	—	13.9	13.9
Other income, net	—	—	—	(3.9)	(3.9)
Income (loss) from continuing operations before income taxes	31.2	11.8	(35.7)	(135.8)	(128.5)
Income tax benefit	—	—	—	(14.6)	(14.6)
Net income (loss) from continuing operations	$ 31.2	$ 11.8	$ (35.7)	$ (121.2)	$ (113.9)

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

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Year Ended December 31, 2015					
Project revenues	$ 150.0	$ 104.6	$ 164.7	$ 0.9	$ 420.2
Segment assets	819.9	228.6	423.8	198.9	1,671.2
Goodwill	47.8	—	86.7	—	134.5
Capital expenditures	7.0	0.5	3.4	0.4	11.3
Project Adjusted EBITDA	$ 104.8	$ 46.9	$ 59.7	$ (2.5)	$ 208.9
Change in fair value of derivative instruments	—	—	(16.0)	0.6	(15.4)
Depreciation and amortization	42.5	39.3	47.2	1.1	130.1
Interest, net	9.8	—	—	—	9.8
Impairment	13.7	—	114.1	—	127.8
Other project expense (income)	0.1		0.1	(2.2)	(2.0)
Project income (loss)	38.7	7.6	(85.7)	(2.0)	(41.4)
Administration	—	—	—	29.4	29.4
Interest, net	—	—	—	107.1	107.1
Foreign exchange gain	—	—	—	(60.3)	(60.3)
Other income, net	—	—	—	(3.1)	(3.1)
Income (loss) from continuing operations before income taxes	38.7	7.6	(85.7)	(75.1)	$ (114.5)
Income tax benefit	—	—	—	(30.4)	(30.4)
Net income (loss) from continuing operations	$ 38.7	$ 7.6	$ (85.7)	$ (44.7)	$ (84.1)

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Year Ended December 31, 2014					
Project revenues	$ 167.1	$ 123.6	$ 198.3	$ 0.9	$ 489.9
Segment assets	1,103.2	396.7	676.8	676.5	2,853.2
Goodwill	61.5	—	135.7	—	197.2
Capital expenditures	3.1	0.4	7.8	1.1	12.4
Project Adjusted EBITDA	$ 106.4	$ 54.2	$ 76.3	$ (7.5)	$ 229.4
Change in fair value of derivative instruments	4.3	—	(11.7)	1.2	(6.2)
Depreciation and amortization	55.0	40.3	59.9	0.7	155.9
Interest, net	20.6	(0.1)	—	—	20.5
Impairment	17.9	50.3	38.5	(0.1)	106.6
Other project expense	(0.1)	(8.7)	0.1	0.2	(8.5)
Project income (loss)	8.7	$ (27.6)	$ (10.5)	$ (9.5)	(38.9)
Administration	—	—	—	37.9	37.9
Interest, net	—	—	—	146.7	146.7
Foreign exchange gain	—	—	—	(38.3)	(38.3)
Other income, net	—	—	—	(0.6)	(0.6)
Income (loss) from continuing operations before income taxes	8.7	(27.6)	(10.5)	(155.2)	(184.6)
Income tax benefit	—	—	—	(31.4)	(31.4)
Net income (loss) from continuing operations	$ 8.7	$ (27.6)	$ (10.5)	$ (123.8)	$ (153.2)

The table below provides information, by country, about our consolidated operations for each of the years ended December 31, 2016, 2015 and 2014 and Property, Plant & Equipment as of December 31, 2016 and 2015, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

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

	Revenue			Property, Plant and Equipment, net of accumulated depreciation	
	2016	2015	2014	2016	2015
United States	$ 236.7	$ 255.5	$ 291.6	$ 499.2	$ 529.6
Canada	162.5	164.7	198.3	234.0	248.1
Total	$ 399.2	$ 420.2	$ 489.9	$ 733.2	$ 777.7

Ontario Electric Financial Corporation ("OEFC"), BC Hydro, and San Diego Gas & Electric provided 29.2%, 11.5%, and 10.9%, respectively, of total consolidated revenues for the year ended December 31, 2016. OEFC, San Diego Gas & Electric, and BC Hydro provided 29.2%, 11.0%, and 10.0%, respectively, of total consolidated revenues for the year ended December 31, 2015. OEFC, San Diego Gas & Electric, and BC Hydro provided 25.8%, 15.1%, and 9.1%, respectively, of total consolidated revenues for the year ended December 31, 2014. IESO and OEFC purchase electricity from the Calstock, Kapuskasing, Nipigon, North Bay and Tunis projects in the Canada segment, respectively. San Diego Gas & Electric purchases electricity from the Naval Station, Naval Training Center, and North Island projects in the West U.S. segment, Georgia Power Company purchases electricity from the Piedmont project in the East U.S. segment, and BC Hydro purchases electricity from the Mamquam, Moresby Lake, and Williams Lake projects in the Canada segment.

23. Commitments and contingencies

Commitments

Operating Lease Commitments

We lease our office properties and equipment under operating leases expiring on various dates through 2022. Certain operating lease agreements over their lease term include provisions for scheduled rent increases. We recognize the effects of these scheduled rent increases on a straight-line basis over the lease term. We also have leased office properties for which we have entered into sub-lease agreements with tenants. The table below excludes leased properties where the net rent expense results in rental income for the company. Lease expense under operating leases was $0.6 million, $1.5 million and $1.0 million for the years ended December 31, 2016, 2015, and 2014, respectively. Future minimum lease commitments under operating leases for the years ending after December 31, 2016, are as follows:

2017	$ 0.7
2018	0.6
2019	0.3
2020	0.1
2021	—
Thereafter	—
	$ 1.7

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

Management Service Commitments

Our Manchief project is operated by a third party under a contract that expires in April 2022. As of December 31, 2016, our commitments under this agreement is estimated as follows:

2017	$ 0.4
2018	0.4
2019	0.4
2020	0.4
2021	0.4
Thereafter	0.2
	$ 2.2

Fuel Supply and Transportation Commitments

We have entered into long-term contractual arrangements to procure fuel and transportation services for our projects. The commitments listed below include only contracts for fuel contracts that are not reimbursed or passed though under the terms of the relevant PPAs. As of December 31, 2016, our commitments under such outstanding agreements are estimated as follows:

2017	$ 2.2
2018	3.8
2019	12.7
2020	10.8
2021	10.7
Thereafter	21.4
	$ 61.6

Guarantees

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

Contingencies

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of December 31, 2016.

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

24. Unaudited selected quarterly financial data

Unaudited selected quarterly financial data are as follows:

	Quarter Ended 2016				
	December 31,	September 30,	June 30,	March 31,	Total
Project revenue	$ 93.4	$ 101.2	$ 98.2	$ 106.4	$ 399.2
Project income (loss)	13.3	(57.1)	25.2	28.7	10.1
Loss from continuing operations	(4.4)	(80.3)	(16.3)	(12.9)	(113.9)
Net loss attributable to Atlantic Power Corporation	(6.6)	(82.4)	(18.5)	(14.9)	(122.4)
Loss per share from continuing operations attributable to Atlantic Power Corporation	$ (0.06)	$ (0.69)	$ (0.15)	$ (0.12)	$ (1.02)
Loss per share attributable to Atlantic Power Corporation	$ (0.06)	$ (0.69)	$ (0.15)	$ (0.12)	$ (1.02)
Weighted average number of common shares outstanding-basic	115.5	119.3	121.6	121.9	119.5
Diluted loss per share from continuing operations attributable to Atlantic Power Corporation	$ (0.06)	$ (0.69)	$ (0.15)	$ (0.12)	$ (1.02)
Diluted loss per share attributable to Atlantic Power Corporation	$ (0.06)	$ (0.69)	$ (0.15)	$ (0.12)	$ (1.02)
Weighted average number of common shares outstanding-diluted[(1)]	115.5	119.3	121.6	121.9	119.5

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

	Quarter Ended 2015				
	December 31,	September 30,	June 30,	March 31,	Total
Project revenue	$ 98.4	$ 107.4	$ 103.1	$ 111.3	$ 420.2
Project (loss) income	(104.3)	24.2	17.2	21.5	(41.4)
(Loss) income from continuing operations	(85.4)	(3.3)	(20.0)	24.6	(84.1)
(Loss) income from discontinued operations	(1.3)	(0.5)	33.6	(12.3)	19.5
Net (loss) income attributable to Atlantic Power Corporation	(88.6)	(6.0)	14.7	17.5	(62.4)
(Loss) income per share from continuing operations attributable to Atlantic Power Corporation	$ (0.71)	$ (0.05)	$ (0.18)	$ 0.18	$ (0.76)
(Loss) income per share from discontinued operations	(0.01)	—	0.30	(0.04)	0.25
(Loss) income per share attributable to Atlantic Power Corporation	$ (0.72)	$ (0.05)	$ 0.12	$ 0.14	$ (0.51)
Weighted average number of common shares outstanding-basic	122.1	122.1	121.9	121.5	121.9
Diluted (loss) income per share from continuing operations attributable to Atlantic Power Corporation	$ (0.71)	$ (0.05)	$ (0.18)	$ 0.18	$ (0.76)
Diluted (loss) income per share from discontinued operations	(0.01)	—	0.30	(0.04)	0.25
Diluted (loss) income per share attributable to Atlantic Power Corporation	$ (0.72)	$ (0.05)	$ 0.12	$ 0.14	$ (0.51)
Weighted average number of common shares outstanding-diluted[(1)]	122.1	122.1	122.1	122.4	121.9
Dividends declared per common share	0.02	0.02	0.02	0.03	0.09

(1) The calculation excludes potentially dilutive shares from convertible debentures and LTIP notional units because their impact would be anti-dilutive.

25. Subsequent Event

On February 27, 2017, we received notification from the OEFC that we will receive a payment of approximately Cdn$8.4 million for our North Bay and Kapuskasing plants representing the application of the price escalator calculation under their respective PPAs for power sold to the OEFC in 2016. The OEFC's interpretation and application of such price escalator calculation is a result of the Superior Court of Ontario's decision in *N-R Power and Energy Corporation v. Ontario Electricity Financial Corporation*.

On January 19, 2017, the Supreme Court of Canada denied the OEFC leave to appeal the Ontario Court of Appeal Decision concerning the interpretation of the price escalator for power sold to the OEFC under certain power purchase agreements with non-utility generators. We were not party to that litigation. We did, however, enter into a standstill agreement with the OEFC in 2015, with respect to our North Bay, Kapuskasing and Tunis projects, arising out of our disagreement with the OEFC over the interpretation of the price escalator calculation in our PPAs. Under the standstill agreement we reserved our right to bring claims against the OEFC and suspended the running of any applicable limitation period to bring such claims.

The OEFC's payment is an adjustment for power sold by our North Bay and Kapuskasing plants only during 2016 and not any prior period. Prior to receipt of the payment, we notified the OEFC that we are reviewing their calculation of the price escalator and reserving our right to contest the payment amount. We will record the payment for this contingent gain as revenue when we settle our dispute with the OEFC and all contingencies have been resolved.

ATLANTIC POWER CORPORATION

SCHEDULE I—CONDENSED BALANCE SHEETS (PARENT COMPANY ONLY)

(in millions of U.S. dollars)

	December 31, 2016	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$ 49.2	$ 11.5
Accounts receivable	—	0.1
Prepayments and other current assets	2.3	3.1
Total current assets	51.5	14.7
Investment in and advances to / from subsidiaries	116.1	480.8
Total assets	$ 167.6	$ 495.5
Liabilities		
Current liabilities:		
Accounts payable and accrued liabilities	$ 1.5	$ 3.1
Total current liabilities	1.5	3.1
Convertible debentures	100.4	277.7
Other long-term liabilities	1.1	0.8
Total liabilities	103.0	281.6
Shareholders' equity	64.6	213.9
Total liabilities and shareholders' equity	$ 167.6	$ 495.5

See accompanying notes to condensed financial statements.

ATLANTIC POWER CORPORATION

SCHEDULE I—CONDENSED STATEMENTS OF OPERATIONS (PARENT COMPANY ONLY)

(in millions of U.S. dollars)

	Year Ended December 31,		
	2016	**2015**	**2014**
Administrative and other expenses:			
Administrative expense	$ 5.9	$ 6.3	$ 12.3
Interest expense, net	7.3	25.6	29.2
Foreign exchange loss (gain)	10.6	(33.0)	(21.0)
Other income	(3.6)	(2.6)	—
Loss from parent company	(20.2)	3.7	(20.5)
Equity losses of subsidiaries, net of income tax benefit	(93.7)	(87.8)	(132.7)
Net loss from continuing operations	(113.9)	(84.1)	(153.2)
Net income (loss) from discontinued operations, net of tax	—	19.5	(29.0)
Net loss	$ (113.9)	$ (64.6)	$ (182.2)

See accompanying notes to condensed financial statements.

ATLANTIC POWER CORPORATION

SCHEDULE I—CONDENSED STATEMENTS OF CASH FLOWS (PARENT COMPANY ONLY)

(in millions of U.S. dollars)

	Years Ended December 31,		
	2016	2015	2014
Cash provided by operating activities:			
Net loss	$ (113.9)	$ (64.6)	$ (182.2)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Non-cash losses from subsidiaries, net of taxes	93.7	87.8	132.7
Dividends received from subsidiaries	33.6	32.5	31.2
Unrealized foreign exchange loss (gain)	10.6	(33.0)	(21.0)
Gain on purchase and cancellation of convertible debentures	(4.7)	(3.1)	(0.6)
Change in other operating balances			
Accounts receivable	11.5	(14.9)	(7.9)
Prepayments and other assets	6.0	13.3	12.7
Accounts payable and accrued liabilities	(1.1)	(23.4)	23.7
Cash provided by operating activities	35.7	(5.4)	(11.4)
Cash provided by investing activities:			
Advances to / from and investments in subsidiaries	216.7	330.4	122.0
Cash provided by investing activities	216.7	330.4	122.0
Cash used in financing activities:			
Common share repurchases	(19.5)	—	—
Dividends paid to common shareholders	—	(11.1)	(34.9)
Repayment of convertible debentures	(187.5)	(18.9)	(43.0)
Payments received from intercompany note	1.5	29.6	106.6
Repayment of intercompany note	(9.2)	—	—
Repayment of long-term debt	—	(319.9)	(140.1)
Cash used in financing activities	(214.7)	(320.3)	(111.4)
Net increase (decrease) in cash and cash equivalents	37.7	4.7	(0.8)
Cash and cash equivalents at beginning of period	11.5	6.8	7.6
Cash and cash equivalents at end of period	$ 49.2	$ 11.5	$ 6.8
Supplemental cash flow information			
Interest paid	$ 11.5	$ 51.1	$ 68.0

See accompanying notes to condensed financial statements

ATLANTIC POWER CORPORATION

SCHEDULE I—NOTES TO CONDENSED FINANCIAL STATEMENTS (PARENT COMPANY ONLY)

(in millions of U.S. dollars)

1. Nature of business

Atlantic Power Corporation (the "Parent Company") is a holding company that conducts substantially all of its business through its subsidiaries. As specified in certain of its subsidiaries' credit agreements, there are restrictions on the Parent Company's ability to obtain funds from certain of its subsidiaries through dividends (refer to Note 11, "Long-term debt", to the consolidated financial statements). As of December 31, 2016, total Atlantic Power Corporation shareholders' equity was $64.6 million and approximately $79.7 million of net assets at certain subsidiaries constituted restricted net assets as defined in Rule 4-08(e)(3) of Regulation S-X. The restricted net assets of these subsidiaries exceeded 25% of our consolidated net assets, thus requiring this Schedule I, "Condensed Financial Information of the Registrant." Accordingly, the balance sheets as of December 31, 2016 and 2015, and the statements of operations and cash flows for the years ended December 31, 2016, 2015 and 2014, have been presented on a "Parent-only" basis. In these statements, the Parent Company's investments in its consolidated subsidiaries are presented under the equity method of accounting. Restricted net assets were approximately $85.2 million at December 31, 2015. We had no undistributed earnings from our unconsolidated investments for the years ended December 31, 2016, 2015 and 2014, respectively.

As disclosed in Note 11, APLP Holdings may be restricted from making dividend payments or other distributions to Atlantic Power Corporation, and APLP and its subsidiaries may be prohibited from making dividends or distributions to Atlantic Power Preferred Equity Limited shareholders in the event of a covenant default or if APLP Holdings fails to achieve a target principal amount on the new term loan that declines quarterly based on a predetermined specified schedule. APLP Holdings has made principal payments to meet the targeted debt balance requirement as of December 31, 2016 and is not prohibited from making dividends to the Parent Company. The consolidated equity of APLP Holdings was approximately $127 million at December 31, 2016 and includes the subsidiaries with restricted net assets of $79.7 million at December 31, 2016 disclosed above.

The Parent-only financial statements should be read in conjunction with our consolidated financial statements included elsewhere herein.

2. Dividends received

The Parent Company received dividends of $33.6 million, $32.5 million and $31.2 million in 2016, 2015 and 2014, respectively, from its consolidated and unconsolidated subsidiaries.

ATLANTIC POWER CORPORATION

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEARS ENDED DECEMBER 31, 2016, 2015 AND 2014

(in millions of U.S. dollars)

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
Income tax valuation allowance, deducted from deferred tax assets:					
Year ended December 31, 2016	$ 175.2	$ 10.8	$ —	$ —	$ 186.0
Year ended December 31, 2015	168.6	6.6	—	—	175.2
Year ended December 31, 2014	128.1	40.5	—	—	168.6

Exhibit 21.1

Subsidiaries of Atlantic Power Corporation

(as of March 2, 2017)

Subsidiary	State of Organization
Atlantic Power Holdings, Inc.	Delaware
Atlantic Power Generation, Inc.	Delaware
Atlantic Power Transmission, Inc.	Delaware
Atlantic Power Services, LLC	Delaware
Atlantic Piedmont Holdings, LLC	Delaware
Atlantic Power (US) GP Holdings, Inc.	Delaware
AP USGP Holdings, LLC	Delaware
Atlantic CDP, Inc.	Delaware
Piedmont Green Power, LLC	Delaware
Atlantic Cadillac Holdings, LLC	Delaware
Cadillac Renewable Energy, LLC	Delaware
Atlantic Power GP Inc.	British Columbia
Orlando Power Generation I, LLC	Delaware
Orlando Power Generation II, LLC	Delaware
Orlando Cogen Limited, LP	Delaware
Baker Lake Hydro, LLC	Delaware
Olympia Hydro, LLC	Delaware
Concrete Hydro Partners, LP	Minnesota
Koma Kulshan Associates, LP	California
Harbor Capital Holdings, LLC	Delaware
Epsilon Power Partners, LLC	Delaware
Chambers Cogeneration LP	Delaware
Atlantic Ridgeline Holdings, LLC.	Delaware
Delta Person LLC	Delaware
Epsilon Power Funding, LLC.	Delaware
Teton East Coast Generation, LLC.	Delaware
Teton Selkirk, LLC	Delaware
Selkirk Cogen Partners LP	Delaware
Selkirk Cogen Funding Corporation	Delaware
Atlantic Power Services Canada GP Inc.	British Columbia
Atlantic Power Services Canada LP	Ontario
Atlantic Power Limited Partnership (f/k/a Capital Power Income L.P.)	Ontario
Atlantic Power GP Inc. (f/k/a CPI Income Services Ltd.)	British Columbia
Atlantic Power Preferred Equity Ltd. (f/k/a CPI Preferred Equity Ltd.)	Alberta
Atlantic Power Energy Services (Canada) Inc. (f/k/a CP Energy Services (Canada) Inc.)	British Columbia
Atlantic Power (US) GP (f/k/a CP Power (US) GP)	Delaware
Atlantic Power (Coastal Rivers) Corporation (f/k/a Coastal Rivers Power Corporation)	British Columbia
Atlantic Power (Williams Lake) Ltd. (f/k/a CPI Power (Williams Lake) Ltd.)	British Columbia
Atlantic Power FPLP Holdings LLC (f/k/a CPI FPLP Holdings LLC)	Delaware
Frederickson Power Management Inc.	Washington
Atlantic Power GP II Inc.	British Columbia
APLP Holdings Limited Partnership	Ontario

Subsidiary	State of Organization
Frederickson Power LP	Washington
APDC, Inc. (f/k/a CPIDC, Inc.)	Washington
AP Power Holdings Inc. (f/k/a CPI Power Holdings Inc.)	Delaware
Atlantic Power USA LLC (f/k/a CPI Power USA LLC)	Delaware
Atlantic Power USA Holdings LLC (f/k/a CPI Power Holdings USA LLC)	Delaware
Atlantic Power Enterprises LLC (f/k/a CPI Power Enterprises LLC)	Delaware
Manchief Inc.	Delaware
Manchief Holding LLC	Delaware
Manchief Power Company LLC	Delaware
Curtis Palmer LLC	Delaware
AP (Curtis Palmer) LLC	Delaware
Curtis/Palmer Hydroelectric Company L.P.	New York
Atlantic Power Energy Services (US) LLC (f/k/a CPI Energy Services (US) LLC)	Delaware
Morris Cogeneration, LLC	Delaware
Atlantic Power USA Ventures, LLC (f/k/a CPI USA Ventures LLC)	Delaware
EF Oxnard LLC	California
EF Kenilworth LLC	California
Applied Energy LLC	California
Ridgeline Energy Holdings Inc.	Delaware
Ridgeline Energy LLC	Delaware
Ridgeline Energy Solar LLC	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Atlantic Power Corporation:

We consent to the incorporation by reference in the registration statements (No. 333-172926 and No. 333-197940) on Form S-8 of Atlantic Power Corporation and subsidiaries (the "Company") of our reports dated March 2, 2017, with respect to the consolidated balance sheets of the Company as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive loss, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2016, and the financial statement schedules I and II in Item 15, and the effectiveness of internal control over financial reporting as of December 31, 2016, which reports appear in the December 31, 2016 annual report on Form 10-K of the Company.

/s/ KPMG LLP
New York, New York
March 2, 2017

Exhibit 31.1

I, James J. Moore, Jr., certify that:

1. I have reviewed this Annual Report on Form 10-K of Atlantic Power Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted account principles;

   c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: March 2, 2017

/s/ JAMES J. MOORE, JR.
James J. Moore, Jr.
President and Chief Executive Officer

Exhibit 31.2

I, Terrence Ronan, certify that:

1. I have reviewed this Annual Report on Form 10-K of Atlantic Power Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted account principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2017

/s/ TERRENCE RONAN
Terrence Ronan
Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer)

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

The undersigned officer of Atlantic Power Corporation (the "Company") hereby certifies to his knowledge that the Company's Annual Report on Form 10-K for the year ended December 31, 2016 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended, and that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company. This certification shall not be deemed "filed" for any purpose, nor shall it be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934 regardless of any general incorporation language in such filing.

Date: March 2, 2017

/s/ JAMES J. MOORE, JR.
James J. Moore, Jr.
President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

The undersigned officer of Atlantic Power Corporation (the “Company”) hereby certifies to his knowledge that the Company’s Annual Report on Form 10-K for the year ended December 31, 2016 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended, and that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company. This certification shall not be deemed “filed” for any purpose, nor shall it be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934 regardless of any general incorporation language in such filing.

Date: March 2, 2017

/s/ TERRENCE RONAN

Terrence Ronan
Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer)