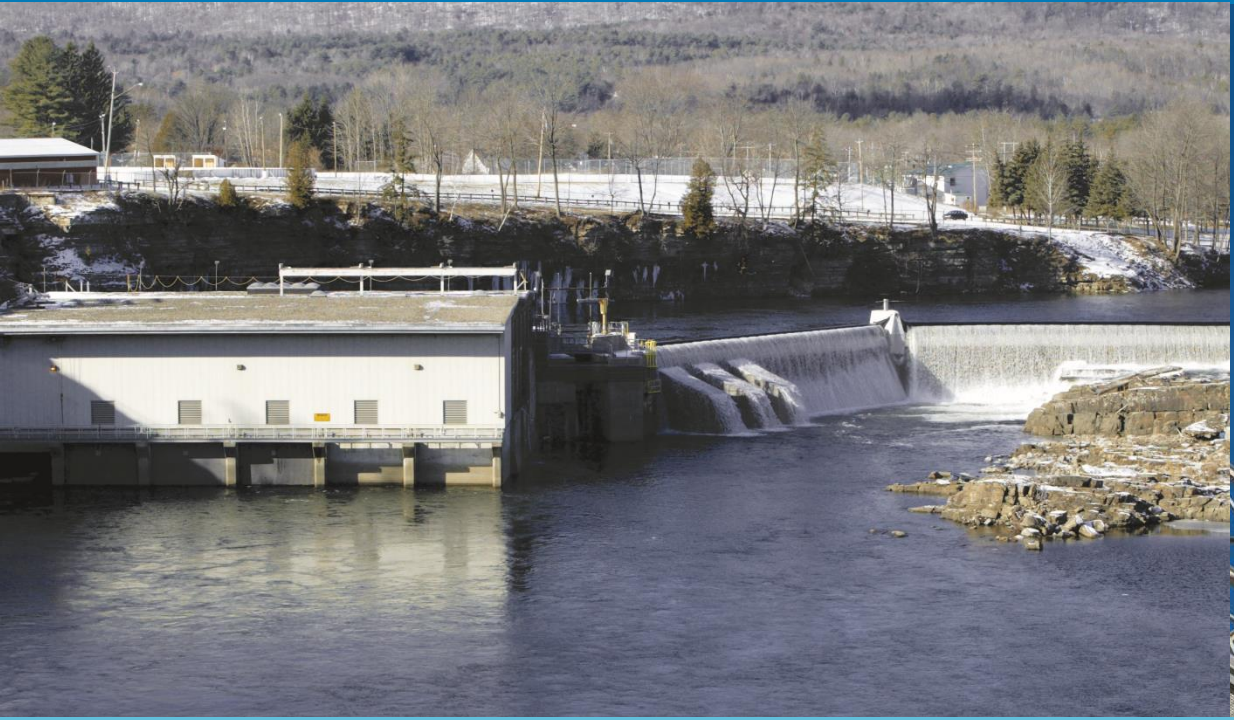
Atlantic Power Corporation



Q3 2018 Financial Results Conference Call

November 2, 2018

Cautionary Note Regarding Forward-Looking Statements

To the extent any statements made in this presentation contain information that is not historical, these statements are forward-looking statements or forward-looking information, as applicable, within the meaning of Section 27A of the U.S. Securities Act of 1933, as amended, and Section 21E of the U.S. Securities Exchange Act of 1934, as amended, and under Canadian securities law (collectively "forward-looking statements").

Forward-looking statements can generally be identified by the use of words such as "should," "intend," "may," "expect," "believe," "anticipate," "estimate," "continue," "plan," "project," "will," "could," "would," "target," "potential" and other similar expressions. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements. Although Atlantic Power Corporation ("AT", "Atlantic Power" or the "Company") believes that the expectations reflected in such forward-looking statements are reasonable, such statements involve risks and uncertainties and should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. Please refer to the factors discussed under "Risk Factors" and "Forward-Looking Information" in the Company's periodic reports as filed with the Securities and Exchange Commission from time to time for a detailed discussion of the risks and uncertainties affecting the Company, including, without limitation, the outcome or impact of the Company's business strategy to increase the intrinsic value of the Company on a per-share basis through disciplined management of its balance sheet and cost structure and investment of its discretionary cash in a combination of organic and external growth projects, acquisitions, and repurchases of debt and equity securities; the Company's ability to enter into new PPAs on favorable terms or at all after the expiration of existing agreements, and the outcome or impact on the Company's business of any such actions. Although the forward-looking statements contained in this presentation are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. These forward-looking statements are made as of the date of this presentation and, except as expressly required by applicable law, the Company assumes no obligation to update or revise them to reflect new events or circumstances. The Company's ability to achieve its longer-term goals, including those described in this presentation, is based on significant assumptions relating to and including, among other things, the general conditions of the markets in which it operates, revenues, internal and external growth opportunities, its ability to sell assets at favorable prices or at all and general financial market and interest rate conditions. The Company's actual results may differ, possibly materially and adversely, from these goals.

Disclaimer – Non-GAAP Measures

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. Investors are cautioned that the Company may calculate this non-GAAP measure in a manner that is different from other companies. The most directly comparable GAAP measure is Project income (loss). Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges), and changes in the fair value of derivative instruments. Management uses Project Adjusted EBITDA at the project level to provide comparative information about project performance and believes such information is helpful to investors. A reconciliation of Project Adjusted EBITDA to Project income (loss) and to Net income (loss) by segment and on a consolidated basis is provided on pages 33-34.

All amounts in this presentation are in US$ and approximate unless otherwise stated.

Agenda

Q3 2018

- Highlights
- Operations Review
- Commercial Update
- Financial Results
- Liquidity and Debt Repayment Profile
- 2018 Guidance
- Q&A

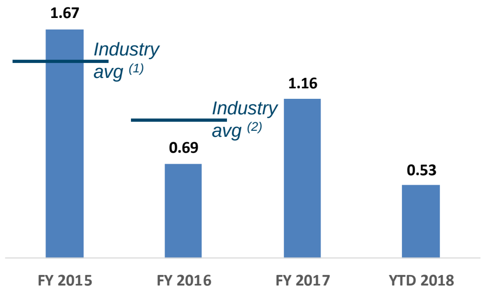
Q3 2018 Highlights

- Third quarter results keep us on track to achieve full year 2018 guidance
- Continued to reduce debt
  - Repaid nearly $21 million; expect to repay $100 million for the full year
- Executed fourth re-pricing of our credit facilities; reduced spread another 25 bp
- Capital allocation:
  - Debt repayment
  - Common and preferred share repurchases
  - First two external investments announced this year (Koma Kulshan, South Carolina biomass)
- Even after capital allocation this quarter, had liquidity at Sept. 30, 2018 of ~$181 million, including ~$32 million of discretionary cash
- Tunis commercial in early October under 15-year PPA
- Nipigon's Long-Term Enhanced Dispatch Contract went into effect this week
- Beginning preparations to decommission the three San Diego facilities

Q3 2018 Operational Performance:

Lower generation due to San Diego PPA expirations and lower water flows at Curtis Palmer

Safety: Total Recordable Incident Rate



(1) 2015 BLS data, generation companies = 1.4
(2) 2016 BLS data, generation companies = 1.0

Availability (weighted average)

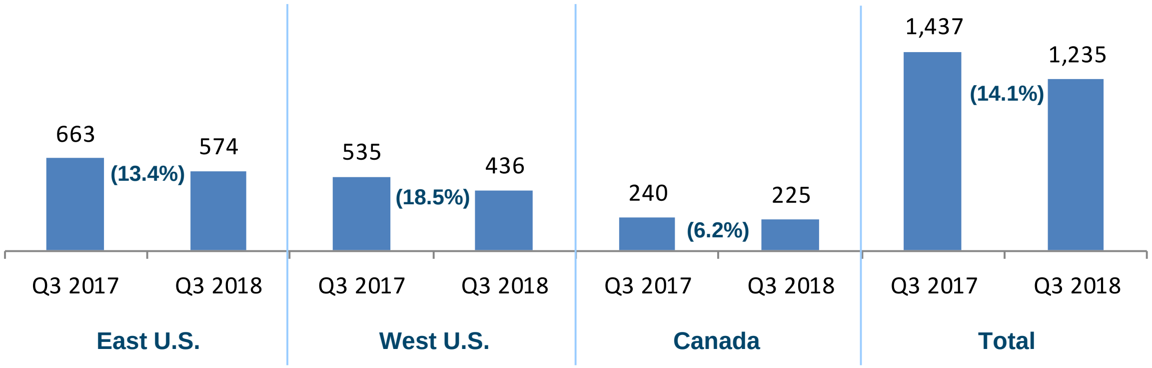
	Q3 2018	Q3 2017
East U.S.	94.0%	98.8%
West U.S.	97.8%	99.0%
Canada	90.2%	97.5%
Total	**94.3%**	**98.6%**

Lower availability factor:

- Morris fall outage taken in September
- Cadillac extended fall outage for upgrade
- Moresby Lake unit down for runner replacements
- Koma Kulshan maintenance outage

\+ Mamquam 100% availability

Aggregate Power Generation Q3 2018 vs. Q3 2017 (Net GWh)



Generation is down:

− Naval Station / North Island / NTC ceased operations in February 2018
− Curtis Palmer lower water flows
− Piedmont maintenance outage in July
\+ Manchief higher dispatch
\+ Frederickson above-average temperatures, lower hydro reserves

Hydro generation

Curtis Palmer	Mamquam
-45% vs Q3 2017	-9% vs Q3 2017
-30% vs long-term avg.	-2% vs long-term avg.

Operations Update

Tunis Re-start

- Commercial operation effective October 4, 2018
  - Will operate in dispatchable mode under a 15-year PPA with the Ontario Independent Electricity System Operator (IESO)
  - Capacity payments are based on an annual average capacity of 36.5 MW
  - Earns energy revenues when operates
- 2018 financial result will be a loss due to the maintenance overhauls required to bring the plant back up
  - Going forward, expect to generate ~US$2 million of Project Adjusted EBITDA annually

Nipigon Long-term Enhanced Dispatch Contract

- Long-term Enhanced Dispatch Contract (LTEDC) went into effect on November 1, 2018 (through Dec. 2022)
  - To operate in simple-cycle mode and generate on a flexible basis (when needed/economic)
  - LTEDC provides for monthly capacity-type payments
  - Will earn energy revenue when operates, but capacity factor expected to be low
  - Improved economics vs. original PPA
- No overhauls required prior to re-start; plan to upgrade control system in 2019

Update on Recent Outages

- Kenilworth – Gas turbine overhaul completed in early September; used leased engine during overhaul
- Fall maintenance outages at Morris, Koma Kulshan, Moresby Lake, and Cadillac (which was extended for upgrade)

Decommissioning of San Diego Sites

- Finalizing scope of work with the Navy
- Expect most of the work to be done in first half of 2019
- Total costs may exceed the $1.7 million accrued
- Cash outlays to occur in 2019

Commercial / PPAs

Williams Lake (British Columbia)

- Short-term contract extension to June 30, 2019 (or Sept. 30, 2019 at BC Hydro's option)
  - Extension is subject to regulatory approval (BC Utilities Commission)
  - Schedule was recently extended again; decision is expected near year-end 2018 or early 2019
  - Date for termination rights to become effective extended to February 28, 2019
- Appeal of amended air permit (to burn alternative fuels)
  - Decision by the Environmental Appeal Board expected Q1 2019
  - Would proceed with investment in a new fuel shredder only if obtain long-term PPA

Ontario

- Continuing marketing efforts for Kapuskasing and North Bay sites
- Re-zoning of North Bay recently approved as part of this effort
  - Allows for various industrial uses
- Nothing substantive to report

Commercial / Acquisitions

South Carolina Biomass Plants

- Agreement signed to acquire two plants from EDF Renewables for $13 million
  - Allendale and Dorchester each 20 MW; in operation since 2013
  - No project-level debt or tax equity to be assumed
- All of the output sold under PPAs with Santee Cooper to 2043
- Closing expected in late Q3 or Q4 2019
- Plants run well, but we see optimization opportunities
  - Availability and output (Atlantic Power biomass standards)
  - Fuel handling
  - Maintenance practices
- ROI is favorable to other external growth options even without optimization
- Expect that optimization initiatives, if successful, would result in very attractive returns

Allendale

Dorchester

Q3 2018 Financial Highlights

Q3 2018 Financial Results	**Project Adjusted EBITDA** **Q3 2018 $45.4 million vs Q3 2017 $77.4 million** (see bridge on page 11) • Decline reflects five PPA expirations, short-term PPA extension at Williams Lake and lower water flows at Curtis Palmer • Results generally in line with expectations • On track for full year 2018 guidance ($170 to $185 million) **Cash Provided by Operating Activities** **Q3 2018 $19.5 million vs Q3 2017 $52.9 million** (see bridge on page 13) • Most of decline attributable to lower Project Adjusted EBITDA • September distribution from Orlando received October 1 ($3.6 million)
Continued Debt Repayment	• Amortized $20 million of term loan and $0.8 million of project debt in Q3 / $79.5 million total YTD Sept. • Consolidated leverage ratio at 9/30/18 of 4.5 times • Liquidity at 9/30/18 of $180.6 million, including ~ $32 million of discretionary cash

Q3 2018 Financial Highlights (continued)

Managing Interest Costs and Risk

- In October, executed fourth re-pricing of term loan and revolver
  - Reduced spread by another 25 bp, to 275 bp over LIBOR
  - Savings (before Q4 transaction cost) of $1.2 million in 2019 and $3.25 million over remaining term
- Exposure to higher interest rates is modest
  - At 9/30/18, more than 96% of our debt was fixed rate or swapped
  - Through September 2019, 92% or more of our debt is either fixed rate or swapped
  - 100 bp change in rates would increase annual interest expense by approx. $450 thousand in 2019

Capital Allocation

Acquisitions

- $12.5 million of cash to acquire remaining 50% interest in Koma Kulshan and buy-out O&M contract
- $2.6 million for deposit on South Carolina biomass acquisition (expected to close late Q3/Q4 2019)

NCIB Update

Q3 2018: Shares repurchased and canceled

- 1.4 million common shares at average price of $2.15/share
  - Total cost $3.1 million

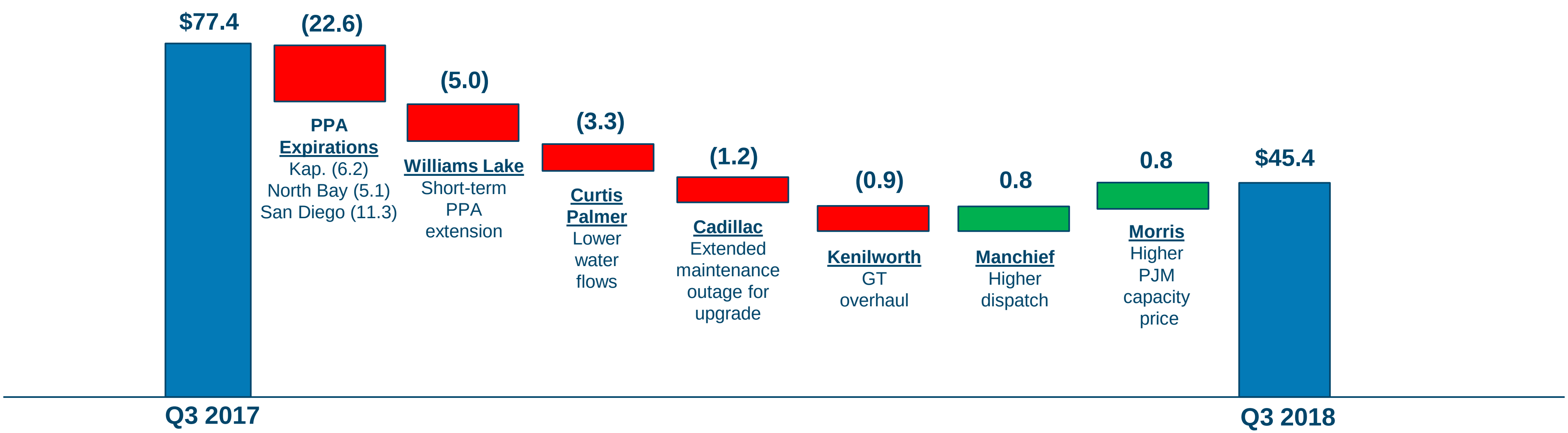
- 237,500 Series 1 preferred shares
- 5,000 Series 2 preferred shares
- 41,695 Series 3 preferred shares
  - Total cost Cdn$4.5 million ($3.4 million US$ equivalent)

October 2018: Shares repurchased and canceled

- 288 thousand common shares at average price $2.15/share
  - Total cost $619 thousand

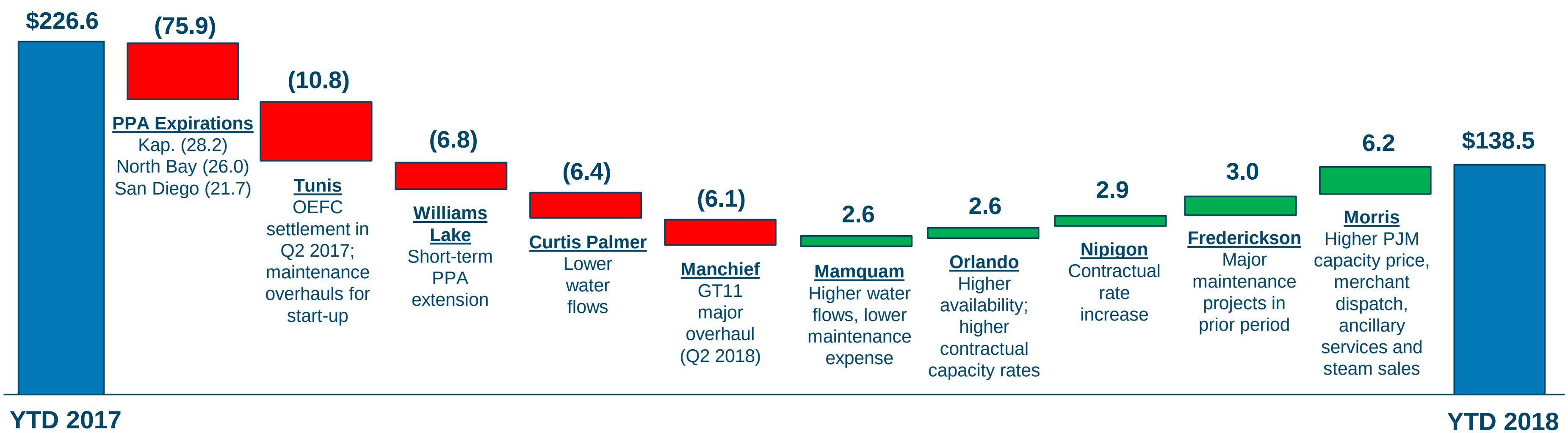
Q3 2018 Project Adjusted EBITDA (bridge vs 2017)

($ millions)



YTD September 2018 Project Adjusted EBITDA (bridge vs 2017)

($ millions)



Q3 and YTD September 2018 Cash Flow Results

($ millions)

	Three months ended Sept. 30,		
Unaudited	**2018**	**2017**	**Change**
Cash provided by operating activities	$19.5	$52.9	$(33.4)
Significant uses of cash provided by operating activities:			
Term loan repayments [1]	(20.0)	(25.0)	5.0
Project debt amortization	(0.8)	(4.4)	3.6
Capital expenditures	(0.1)	(1.5)	1.4
Preferred dividends	(2.1)	(2.3)	0.2

Primary drivers:

- Lower Project Adjusted EBITDA -32.0
- Delayed Orlando distribution -3.6
- Lower cash interest payments +0.7

	Nine months ended Sept. 30,		
Unaudited	**2018**	**2017**	**Change**
Cash provided by operating activities	$97.8	$138.7	$(40.9)
Significant uses of cash provided by operating activities:			
Term loan repayments [1]	(70.0)	(77.1)	7.1
Project debt amortization	(9.5)	(9.1)	(0.4)
Capital expenditures	(1.4)	(5.7)	4.3
Preferred dividends	(6.3)	(6.5)	0.2

Primary drivers:

- Lower Project Adjusted EBITDA -88.1
- Changes in working capital (primarily related to five PPA expirations) +34.6
- Lower cash interest payments +13.9

[1] Includes 1% mandatory annual amortization and targeted debt repayments.

Liquidity

($ millions)

	Sep 30, 2018	Jun 30, 2018
Cash and cash equivalents, parent	$39.1	$49.2
Cash and cash equivalents, projects	18.5	31.6
Total cash and cash equivalents	**57.6**	**80.8**
Revolving credit facility	200.0	200.0
Letters of credit outstanding	(77.0)	(77.4)
Availability under revolving credit facility	**123.0**	**122.6**
Total Liquidity	**$180.6**	**$203.4**
Excludes restricted cash of:	$0.3	$1.9
Consolidated debt (1)	**$762.0**	**$778.1**
Leverage ratio (2)	**4.5**	**3.8**

During the second and third quarters, several projects released excess cash to the parent due to lower working capital needs (five projects not in operation).

In Q3 2018, we used discretionary cash at parent of $6.5 million for the repurchase of common and preferred shares, $12.5 million for the purchase of the remaining interest in Koma Kulshan and the buy-out of the O&M contract, and $2.6 million for a deposit on two biomass plants in South Carolina (expected to close H2 2019).

(1) Before unamortized discount and unamortized deferred financing costs

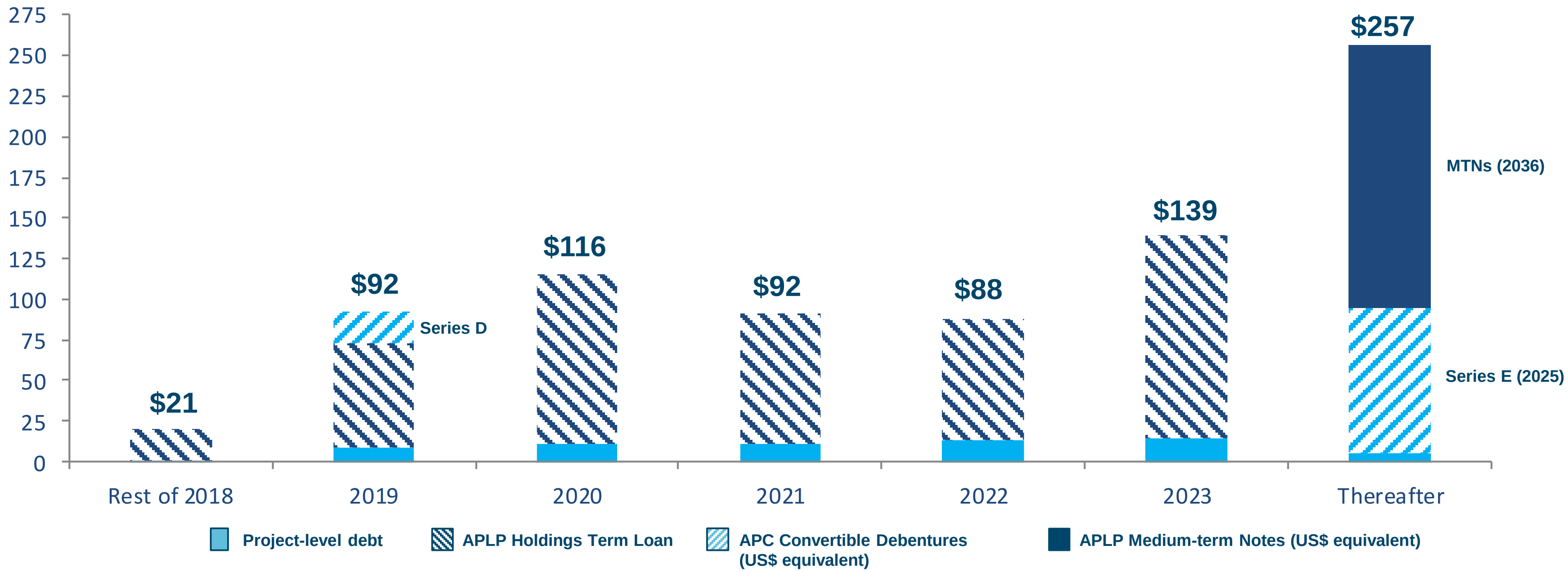
(2) Consolidated gross debt to trailing 12-month Adjusted EBITDA (after Corporate G&A)

Debt Repayment Profile at September 30, 2018 (1)

($ millions)

Total $805

51% amortizing, 49% bullet (2)

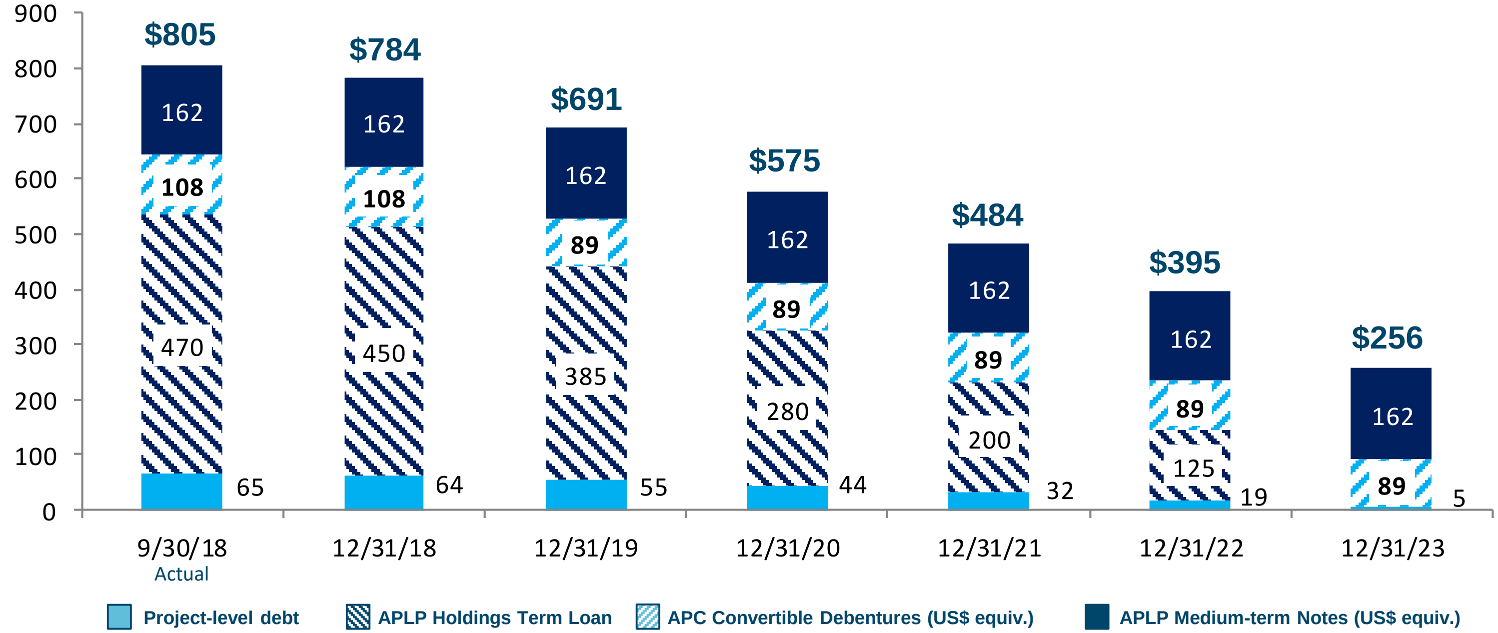


- Project-level non-recourse debt totals $65, including $43 at Chambers (equity method); amortizes over the life of the project PPAs (through 2025)
- $470 amortizing term loan (maturing in April 2023), which has 1% annual amortization and mandatory prepayment via the greater of a 50% sweep or such other amount that is required to achieve a specified targeted debt balance (combined average annual repayment of ~ $83)
- $19 (US$ equivalent) of Series D and $89 (US$ equivalent) of Series E convertible debentures (maturing in Dec 2019 and Jan 2025, respectively)
- $162 (US$ equivalent) APLP Medium-Term Notes due in 2036

(1)) Includes Company's proportional share of debt at Chambers of $43 million, which is not consolidated because the project is 40% owned. (2) Bullet percentage includes remaining term loan balance at maturity in April 2023. Note: C$ denominated debt was converted to US$ using US$ to C$ exchange rate of $1.2945.

Projected Debt Balances through 2023 (1)

($ millions)



Expected Debt Repayment (September 30, 2018 – Year-end 2023):

- Term loan – Amortize $345; $125 remaining balance due at maturity in April 2023 (2)
- Project debt (proportional) – Repay $60, ending balance $5
- Series D convertible debentures mature Dec. 2019 ($19 US$ equivalent)

(1)) Includes Company's proportional share of debt at Chambers of $43 million, which is not consolidated because the project is 40% owned (2) Assumes repayment at maturity; alternative paths include an extension of maturity date or refinancing prior to maturity. Note: C$ denominated debt was converted to US$ using US$ to C$ exchange rate of $1.2945.

Bridge of 2018 Project Adjusted EBITDA Guidance to Cash Provided by Operating Activities

($ millions)

	2018 Guidance (as of 3/1/18)	2017 Actual
Project Adjusted EBITDA	**$170 - $185**	**$288.8**
Adjustment for equity method projects [(1)]	(2)	(6.4)
Corporate G&A expense	(22)	(23.6)
Cash interest payments	(45)	(72.0)
Cash taxes	(4)	(4.4)
Other	-	(13.2)
Cash provided by operating activities	**$95 - $110**	**$169.2**

Before $1.4 million credit included in Project Adjusted EBITDA; total expense $22.2 million.

Note: For purposes of providing a reconciliation of Project Adjusted EBITDA guidance, impact on Cash provided by operating activities of changes in working capital is assumed to be nil.

2018 Planned Uses of Cash Provided by Operating Activities:

- Term loan repayments $90
- Project debt repayments ~$10
- Preferred dividends ~$8
- Capital expenditures ~$2

The Company has not provided guidance for Project income or Net income because of the difficulty of making accurate forecasts and projections without unreasonable efforts with respect to certain highly variable components of these comparable GAAP metrics, including changes in the fair value of derivative instruments and foreign exchange gains or losses. These factors, which generally do not affect cash flow, are not included in Project Adjusted EBITDA.

(1) Represents difference between Project Adjusted EBITDA and cash distribution from equity method projects

Appendix

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AtlanticPower Corporation

Power Projects and PPA Expiration Dates

Year	Project	Location	Type	Economic Interest	Net MW	Contract Expiry
2019	Williams Lake	B.C.	Biomass	100%	66	6/2019 (1)
	Kenilworth	New Jersey	Nat. Gas	100%	29	9/2019 (2)
2020	Oxnard	California	Nat. Gas	100%	49	4/2020 (3)
	Calstock	Ontario	Biomass	100%	35	6/2020
2021	None expiring					
2022	Manchief	Colorado	Nat. Gas	100%	300	4/2022 (4)
	Moresby Lake	B.C.	Hydro	100%	6	8/2022
	Frederickson	Washington	Nat. Gas	50.15%	125	8/2022
	Nipigon	Ontario	Nat. Gas	100%	40	12/2022
2023	Orlando	Florida	Nat. Gas	50%	65	12/2023
2024	Chambers	New Jersey	Coal	40%	105	3/2024
2025 - 2028	Mamquam	B.C.	Hydro	100%	50	9/2027 (5)
	Curtis Palmer	New York	Hydro	100%	60	12/2027 (6)
	Cadillac	Michigan	Biomass	100%	40	6/2028
2032 - 2037	Piedmont	Georgia	Biomass	100%	55	9/2032
	Tunis	Ontario	Nat. Gas	100%	40	10/2033 (7)
	Morris	Illinois	Nat. Gas	100%	177	12/2034 (8)
	Koma Kulshan	Washington	Hydro	100%	13	3/2037

(1) May be extended to Sept. 2019 at BC Hydro's option. (2) Merck has two additional successive one-year extension options. (3) Oxnard's steam sales agreement expires in February 2020. (4) Public Service Co. of Colorado has option to purchase Manchief that is exercisable in May 2020 and May 2021. (5) BC Hydro has an option to purchase Mamquam that is exercisable in November 2021. (6) Expires at the earlier of Dec. 2027 or the provision of 10,000 GWh of generation. Based on cumulative generation to date, we expect the PPA to expire prior to Dec. 2027. (7) 15-year contract commenced October 4, 2018. (8) Equistar has an option to purchase Morris that is exercisable in December 2020 and December 2027.

Capitalization

($ millions)

	Sep. 30, 2018		Dec. 31, 2017	
Long-term debt, incl. current portion (1)				
APLP Medium-Term Notes (2)	$162.2		$167.4	
Revolving credit facility	-		-	
Term Loan	470.0		540.0	
Project-level debt (non-recourse)	21.8		31.2	
Convertible debentures (2)	107.9		107.0	
Total long-term debt, incl. current portion	**$762.0**	**81%**	**$845.5**	**81%**
Preferred shares (3)	199.3	21%	215.2	21%
Common equity (4)	(21.5)	(2)%	(18.4)	(2)%
Total shareholders equity	**$177.8**	**19%**	**$196.8**	**19%**
Total capitalization	**$939.8**	**100%**	**$1,042.2**	**100%**

(1) Debt balances are shown before unamortized discount and unamortized deferred financing costs
(2) Period-over-period change due to F/X impacts
(3) Par value of preferred shares was approximately $157 million and $175 million at Sept. 30, 2018 and December 31, 2017, respectively.
(4) Common equity includes other comprehensive income and retained deficit

Note: Table is presented on a consolidated basis and excludes equity method projects

Capital Summary at September 30, 2018

($ millions)

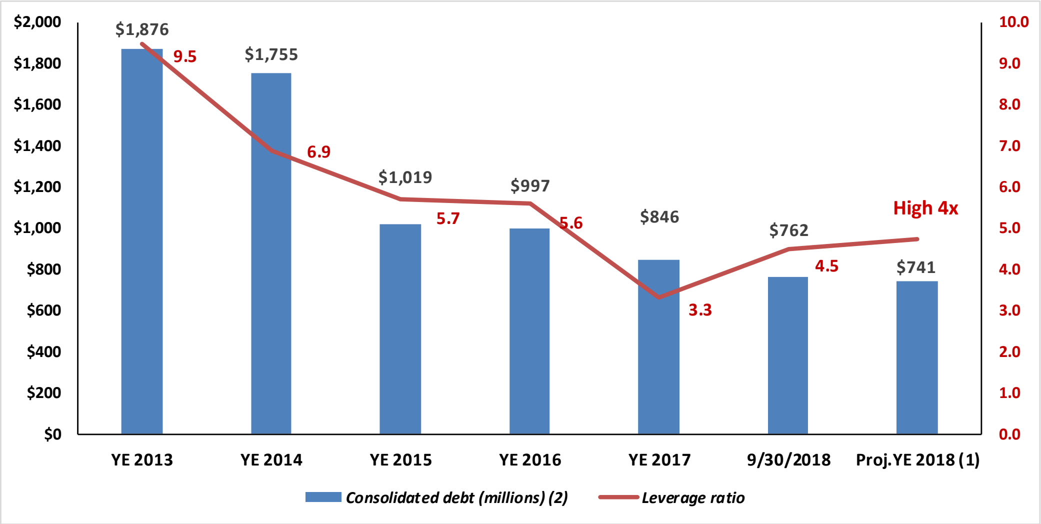
Atlantic Power Corporation			
	Maturity	**Amount**	**Interest Rate**
Convertible Debentures (ATP.DB.D)	12/2019	$19.1 (C$24.7)	6.00%
Convertible Debentures (ATP.DB.E)	1/2025	$88.8 (C$115.0)	6.00%
APLP Holdings Limited Partnership			
	Maturity	**Amount**	**Interest Rate**
Revolving Credit Facility	4/2022	$0	LIBOR + 3.00% (1)
Term Loan	4/2023	$470.0	3.87%-5.42% (2)
Atlantic Power Limited Partnership			
	Maturity	**Amount**	**Interest Rate**
Medium-term Notes	6/2036	$162.2 (C$210)	5.95%
Preferred shares (AZP.PR.A)	N/A	$82.6 (C$106.9)	4.85%
Preferred shares (AZP.PR.B)	N/A	$45.0 (C$58.3)	5.57%
Preferred shares (AZP.PR.C)	N/A	$28.9 (C$37.4)	5.35% (3)
Atlantic Power Transmission & Atlantic Power Generation			
	Maturity	**Amount**	**Interest**
Project-level Debt (consolidated)	Various	$21.8	6.14%-6.38%
Project-level Debt (equity method)	Various	$42.9	4.50%-5.00%

(1) Spread reduced to LIBOR +2.75% effective October 31, 2018. (2) Weighted average rate at Sept 30, 2018 of 4.39%. Range and weighted average include impact of interest rate swaps (3) Set on June 1, 2018 for Sept 28, 2018 dividend payment. Will be reset quarterly based on sum of the Canadian Government 90-day Treasury Bill yield (using the three-month average result plus 4.18%). Note: C$ denominated debt was converted to US$ using US$ to C$ exchange rate of $1.2945.

Strengthening Balance Sheet, Reducing Cash Interest Payments and Corporate Overheads

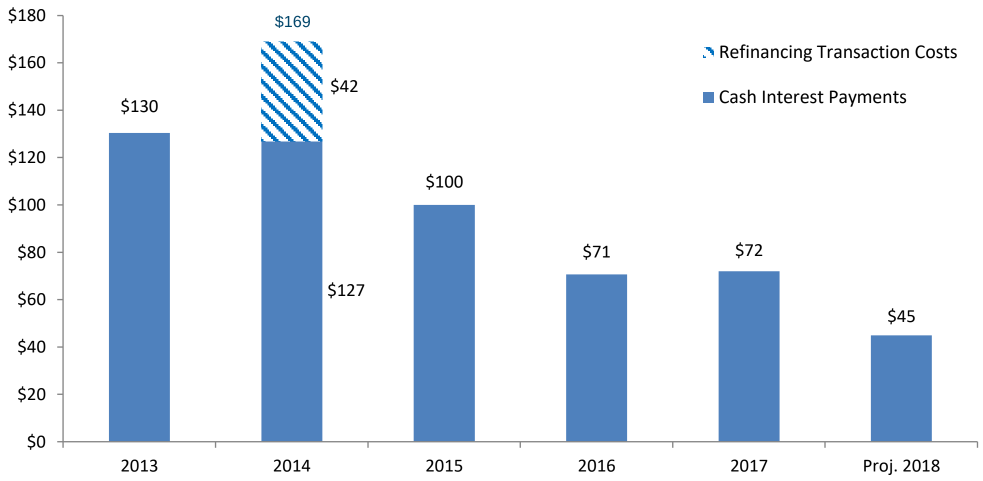
($ millions)

Total net reduction in consolidated debt since YE 2013 of more than $1.1 billion

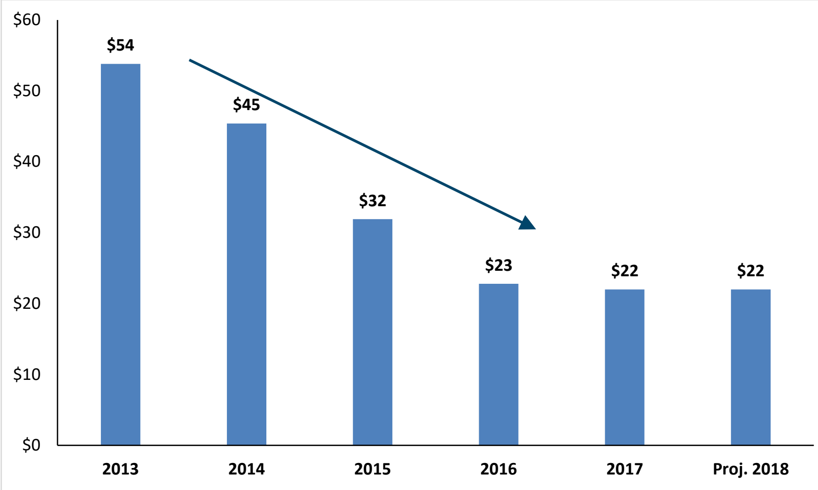


Leverage ratio expected to increase by YE 2018 (due to lower Projected Adjusted EBITDA), but we expect continuing debt repayment to move it lower in 2019

Cash interest payments [(3)] reduced approximately $85 million (65%) since 2013 (due to debt repayment and re-pricings of credit facilities)



G&A expense[(4)]: Approx. 60% reduction from 2013 level



[(1)] Assumes $100 million of debt repayments in 2018. [(2)] Excludes unamortized discounts and deferred financing costs. [(3)] Consolidated debt only. [(4)] General and administrative – Corporate overhead and project development expense.

APLP Holdings Term Loan Cash Sweep Calculation

APLP Holdings Adjusted EBITDA
(note: excludes Piedmont; is after majority of Atlantic Power G&A expense)

Less:
Capital expenditures
Cash taxes

= Cash flow available for debt service

Less:
APLP Holdings consolidated cash interest
(revolver, term loan, MTNs, EPP, Cadillac)

= Cash flow available for cash sweep

Calculate 50% of cash flow available for sweep
Compare 50% cash flow sweep to amount required to achieve targeted debt balance

Must repay greater of 50% or the amount required to achieve targeted debt balance for that quarter

If targeted debt balance is > 50% of cash flow sweep:
- Repay amount required to achieve target, up to 100% of cash flow available from sweep
- Remaining amount, if any, to Company

If targeted debt balance is < 50% of cash flow sweep:
- Repay 50% minimum
- Remaining 50% to Company

Expect cash sweep to average 65% to 70% over the life of the loan, though higher in early years, and with considerable variability from year to year

Expect > 80% of principal to be repaid by maturity through mandatory and targeted repayments

Notes:
The cash sweep calculation occurs at each quarter-end. Targeted debt balances are specified in the credit agreement for each quarter through maturity.

APLP Holdings Credit Facilities – Financial Covenants

Fiscal Quarter	Leverage Ratio	Interest Coverage Ratio
9/30/2018	5.00:1.00	3.00:1.00
12/31/2018	5.00:1.00	3.00:1.00
3/31/2019	5.00:1.00	3.00:1.00
6/30/2019	5.00:1.00	3.25:1.00
9/30/2019	5.00:1.00	3.25:1.00
12/31/2019	5.00:1.00	3.25:1.00
3/31/2020	5.00:1.00	3.25:1.00
6/30/2020	4.25:1.00	3.50:1.00
9/30/2020	4.25:1.00	3.50:1.00
12/31/2020	4.25:1.00	3.50:1.00
3/31/2021	4.25:1.00	3.50:1.00
6/30/2021	4.25:1.00	3.75:1.00
9/30/2021	4.25:1.00	3.75:1.00
12/31/2021	4.25:1.00	3.75:1.00
3/31/2022	4.25:1.00	3.75:1.00
6/30/2022	4.25:1.00	4.00:1.00
9/30/2022	4.25:1.00	4.00:1.00
12/31/2022	4.25:1.00	4.00:1.00
3/31/2023	4.25:1.00	4.00:1.00

Leverage ratio:

Consolidated debt to Adjusted EBITDA, calculated for the trailing four quarters.

Consolidated debt includes both long-term debt and the current portion of long-term debt at APLP Holdings, specifically the amount outstanding under the term loan and the amount borrowed under the revolver, if any, the Medium Term Notes, and consolidated project debt (Epsilon Power Partners and Cadillac).

Adjusted EBITDA is calculated as the Consolidated Net Income of APLP Holdings plus the sum of consolidated interest expense, tax expense, depreciation and amortization expense, and other non-cash charges, minus non-cash gains. The Consolidated Net Income includes an allocation of the majority of Atlantic Power G&A expense. It also excludes earnings attributable to equity-owned projects but includes cash distributions received from those projects.

Interest Coverage ratio:

Adjusted EBITDA to consolidated cash interest payments, calculated for the trailing four quarters.

Adjusted EBITDA is defined above.

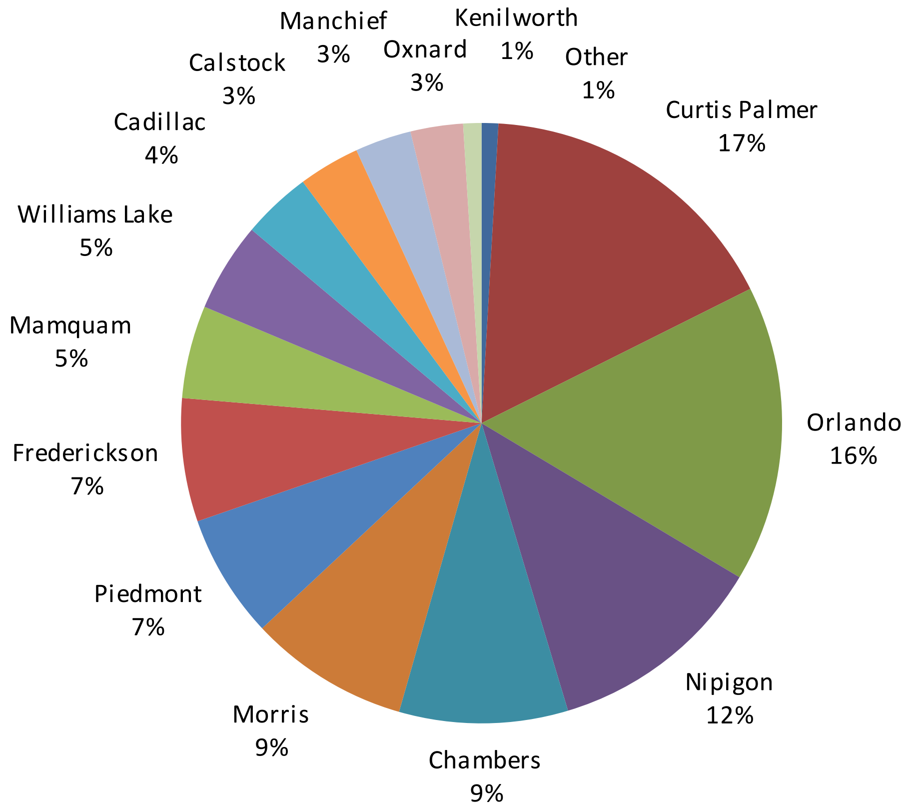
Consolidated cash interest payments include interest payments on the debt included in the Consolidated debt ratio defined above.

Note, the project debt, Project Adjusted EBITDA and cash interest expense for Piedmont are not included in the calculation of these ratios because the project is not included in the collateral package for the credit facilities.

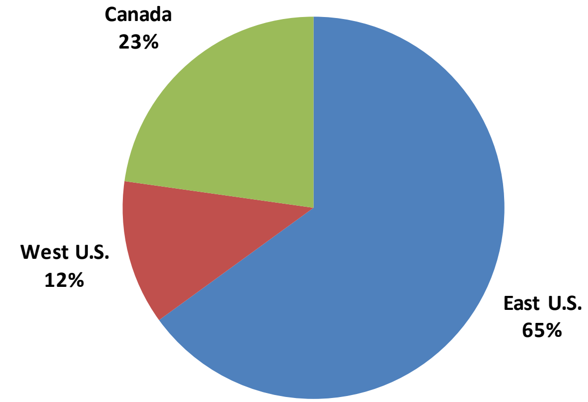
Project Adjusted EBITDA and Cash Flow Diversification by Project

Nine months ended September 30, 2018

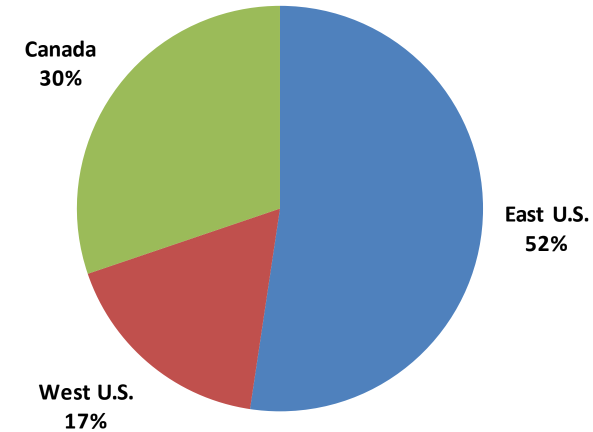
Project Adjusted EBITDA by Project



Project Adjusted EBITDA by Segment [(1)]



Cash Distributions from Projects by Segment [(2)]

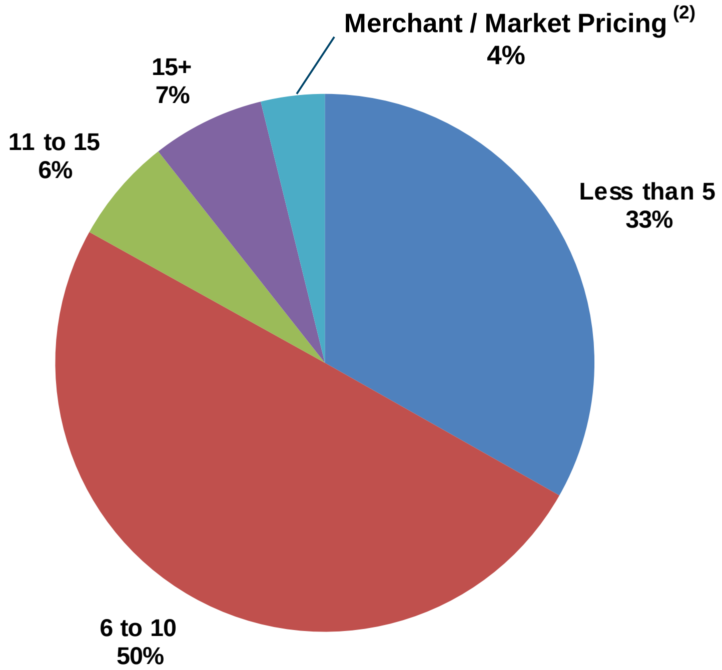


[(1)] Based on Project Adjusted EBITDA for the nine months ended September 30, 2018, excluding non-operational projects and one other project that has negative Project Adjusted EBITDA for the period. Un-allocated corporate segment is included in “Other” category for project percentage allocation and allocated equally among segments for nine months ended Sept. 30, 2018 Project Adjusted EBITDA by Segment.
[(2)] Based on $142.0 million in Cash Distributions from Projects for the nine months ended September 30, 2018.

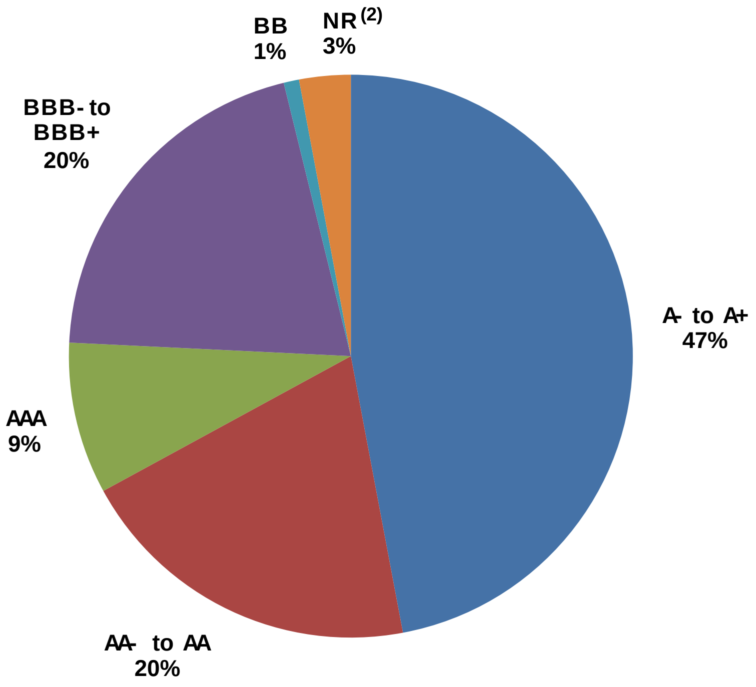
Majority of Cash Flows Covered by Contracts with More Than 5 Years Remaining

Contracted projects have an average remaining PPA life of 6.3 years (1)

Remaining PPA Term (years) (1)



Pro Forma Offtaker Credit Rating (1)



Approximately two-thirds of 2018 Project Adjusted EBITDA generated from PPAs that expire after 2022

(1) Weighted by FY 2018 Project Adjusted EBITDA. PPA's for San Diego assets terminated on March 1, 2018.
(2) Primarily merchant revenues at Morris

Results Summary, Q3 and YTD Sept 2018 vs Q3 and YTD Sept 2017

($ millions, unaudited)

Summary of Financial and Operating Results

	Three months ended September 30		Nine months ended September 30	
	2018	2017	2018	2017
Financial Results				
Project revenue	$65.4	$108.6	$211.6	$331.0
Project income (loss)	26.2	(20.9)	68.0	(7.7)
Net (loss) income attributable to Atlantic Power Corp.	(3.2)	(32.9)	12.1	(57.5)
Cash provided by operating activities	19.5	52.9	97.8	138.7
Project Adjusted EBITDA	45.4	77.4	138.5	226.6
Operating Results				
Aggregate power generation (net GWh)	1,234.6	1,437.0	3,335.0	3,720.0
Weighted average availability	94.3%	98.6%	95.4%	92.9%

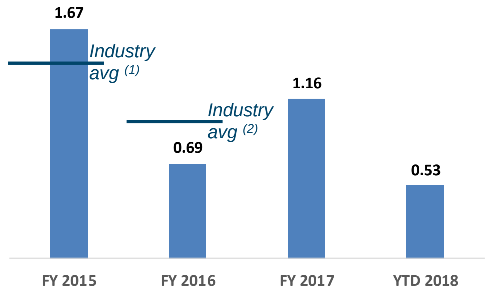
Segment Results

	Three months ended September 30		Nine months ended September 30	
	2018	2017	2018	2017
Project income (loss)				
East U.S.	$12.7	$15.0	$51.5	($16.4)
West U.S.	12.6	(46.2)	4.4	(46.4)
Canada	1.2	9.4	9.8	51.6
Un-allocated Corporate	(0.3)	0.9	2.3	3.5
Total	**26.2**	**(20.9)**	**68.0**	**(7.7)**
Project Adjusted EBITDA				
East U.S.	$25.5	$30.6	$89.8	$86.8
West U.S.	11.5	21.7	16.9	41.5
Canada	8.3	24.6	31.5	97.3
Un-allocated Corporate	0.1	0.5	0.3	1.0
Total	**45.4**	**77.4**	**138.5**	**226.6**

YTD September 2018 Operational Performance:

Lower generation due to San Diego PPA expirations, but availability improved

Safety: Total Recordable Incident Rate



[1] 2015 BLS data, generation companies = 1.4
[2] 2016 BLS data, generation companies = 1.0

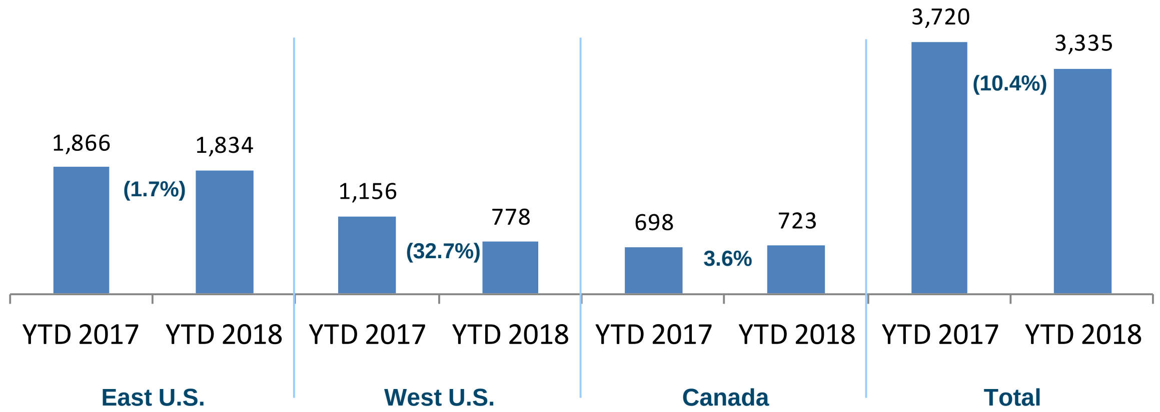
Availability (weighted average)

	YTD 2018	YTD 2017
East U.S.	95.8%	94.1%
West U.S.	94.6%	89.9%
Canada	95.4%	91.8%
Total	**95.4%**	**92.9%**

Higher availability factor:

+ Frederickson maintenance outage in prior period
+ Mamquam forced outage in prior period
+ Orlando shorter spring outage in 2018
+ Kenilworth maintenance outage in prior period
- Manchief gas turbine overhaul in 2018
- Moresby Lake maintenance outage in 2018

Aggregate Power Generation YTD Sept 2018 vs. YTD Sept 2017 (Net GWh)



Generation is down:

− Naval Station / North Island / NTC ceased operations in February 2018
− Curtis Palmer lower water flows
− Piedmont maintenance outage
− Selkirk was sold in Q4 2017
+ Manchief higher dispatch
+ Orlando shorter spring maintenance outage this year
+ Morris higher PJM dispatch
+ Mamquam higher water flows in 2018, forced outage in prior period

Hydro generation

Curtis Palmer	Mamquam
-23% vs YTD Sept 2017	+17% vs YTD Sept. 2017
-6% vs long-term avg.	+15% vs long-term avg.

AtlanticPower Corporation

Project Income (Loss) by Project, Q3 and YTD Sept 2018 vs Q3 and YTD Sept 2017

($ millions)

	Three months ended September 30		Nine months ended September 30	
	2018	**2017**	**2018**	**2017**
East U.S.				
Cadillac	($0.6)	$0.5	$1.4	$2.3
Curtis Palmer	(0.3)	2.9	12.7	19.1
Kenilworth	(0.5)	0.3	(0.6)	(0.2)
Morris	2.1	1.6	6.9	2.3
Piedmont	4.0	1.5	4.2	(1.7)
Chambers [(1)]	0.5	1.1	5.2	(42.8)
Orlando [(1)]	7.5	7.1	21.7	16.2
Selkirk [(1)] [(2)]	-	-	-	(11.6)
Total	**12.7**	**15.0**	**51.5**	**(16.4)**
West U.S.				
Manchief	1.8	1.0	(3.9)	2.2
Naval Station	(0.5)	(20.2)	(1.8)	(19.5)
Naval Training Center	(0.4)	(19.1)	(1.6)	(17.8)
North Island	(0.5)	(12.4)	(1.5)	(11.9)
Oxnard	3.6	3.4	0.9	0.8
Frederickson [(1)]	1.9	1.0	5.2	(0.8)
Koma Kulshan [(3)]	6.7	0.1	7.1	0.6
Total	**12.6**	**(46.2)**	**4.4**	**(46.4)**
Canada				
Calstock	0.9	0.9	3.2	2.5
Kapuskasing	(0.1)	1.4	(0.4)	14.3
Mamquam	1.3	1.2	6.0	3.5
Nipigon	(0.5)	1.1	0.4	3.1
North Bay	(0.1)	1.3	(0.2)	14.6
Williams Lake	0.5	3.7	5.7	7.4
Other	(0.8)	(0.2)	(4.9)	6.2
Total	**1.2**	**9.4**	**9.8**	**51.6**
Totals				
Consolidated projects	16.6	(31.1)	33.2	27.2
Equity method projects	9.9	9.3	32.5	(38.4)
Un-allocated corporate	(0.3)	0.9	2.3	3.5
Total Project Income (Loss)	**$26.2**	**($20.9)**	**$68.0**	**($7.7)**

[(1)] Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates. [(2)] Project sold in November 2017. [(3)] Consolidated as of July 27, 2018; equity investment prior to that date. For purpose of Q3, is included in the Consolidated subtotal.

Project Adjusted EBITDA by Project, Q3 and YTD Sept 2018 vs Q3 and YTD Sept 2017

($ millions)

		Three months ended September 30		Nine months ended September 30	
		2018	2017	2018	2017
East U.S.	**Accounting**				
Cadillac	Consolidated	$0.7	$1.9	$5.4	$6.4
Curtis Palmer	Consolidated	3.5	6.8	24.3	30.8
Kenilworth	Consolidated	0.1	1.0	1.4	1.7
Morris	Consolidated	4.3	3.5	12.5	6.3
Piedmont	Consolidated	5.8	6.0	9.7	9.5
Chambers [(1)]	Equity method	3.1	3.8	13.2	12.5
Orlando [(1)]	Equity method	7.9	7.7	23.2	20.7
Selkirk [(1)] [(2)]	Equity method	-	0.0	-	(1.0)
Total		**25.5**	**30.6**	**89.8**	**86.8**
West U.S.					
Manchief	Consolidated	4.6	3.8	4.4	10.5
Naval Station	Consolidated	(0.5)	4.1	(0.7)	8.1
Naval Training Center	Consolidated	(0.4)	2.2	(0.9)	4.3
North Island	Consolidated	(0.5)	3.6	(0.6)	7.1
Oxnard	Consolidated	4.7	4.4	4.1	4.0
Frederickson [(1)]	Equity method	3.4	3.5	9.7	6.6
Koma Kulshan [(3)]	Consolidated	0.2	0.1	0.9	0.9
Total		**11.5**	**21.7**	**16.9**	**41.5**
Canada					
Calstock	Consolidated	1.5	1.5	4.8	4.1
Kapuskasing	Consolidated	(0.1)	6.1	(0.4)	27.8
Mamquam	Consolidated	1.7	1.6	7.3	4.7
Moresby Lake	Consolidated	(0.3)	0.2	0.1	0.4
Nipigon	Consolidated	4.9	4.4	17.1	14.3
North Bay	Consolidated	(0.1)	5.0	(0.2)	25.8
Tunis	Consolidated	(0.2)	(0.2)	(4.3)	6.5
Williams Lake	Consolidated	0.9	5.9	7.0	13.8
Total		**8.3**	**24.6**	**31.5**	**97.3**
Totals					
Consolidated projects		30.9	61.7	91.4	185.9
Equity method projects		14.5	15.2	46.8	39.7
Un-allocated corporate		0.1	0.5	0.3	1.0
Total Project Adjusted EBITDA		**$45.4**	**$77.4**	**$138.5**	**$226.6**

	Three months ended September 30		Nine months ended September 30	
	2018	2017	2018	2017
Total Project Adjusted EBITDA	**$45.4**	**$77.4**	**$138.5**	**$226.6**
Change in fair value of derivative instruments	-	2.0	(3.5)	5.8
Depreciation and amortization	25.0	36.6	78.0	105.6
Interest, net	(0.6)	2.5	2.7	8.0
Impairment	-	57.3	-	57.3
Other project (income) expense	(5.2)	(0.1)	(6.7)	57.6
Project income	**$45.4**	**$77.4**	**$68.0**	**($7.7)**
Administration	5.7	5.5	17.9	17.6
Interest expense, net	14.6	13.8	40.7	49.5
Foreign exchange loss (gain)	4.5	9.4	(9.1)	17.7
Other income, net	2.5	-	0.3	-
(Loss) income before income taxes	(1.1)	(49.6)	18.2	(92.5)
Income tax expense (benefit)	3.6	(15.9)	7.7	(38.5)
Net (loss) income	**($4.7)**	**($33.7)**	**$10.5**	**($54.0)**
Net (loss) income	(1.5)	(0.8)	(1.6)	3.5
Net (loss) income attributable to Atlantic	**($3.2)**	**($32.9)**	**$12.1**	**($57.5)**

[(1)] Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates . [(2)]Project sold in November 2017 . [(3)] Consolidated as of July 27, 2018; equity investment prior to that date. For purpose of Q3, is included in the Consolidated subtotal.

Cash Distributions from Projects by Quarter, 2017 and 2018

($ millions), Unaudited

	Q1 2017	Q2 2017	Q3 2017	Q4 2017	FY 2017	Q1 2018	Q2 2018	Q3 2018	YTD 2018
East U.S.									
Cadillac	$0.3	$1.3	$1.0	$1.0	$3.5	$0.3	$1.3	$1.0	$2.5
Curtis Palmer	9.9	13.5	8.5	7.5	39.3	9.5	13.0	2.7	25.1
Kenilworth	0.7	0.7	0.2	0.7	2.3	1.4	0.5	(0.0)	1.8
Morris	0.5	0.3	(1.2)	5.6	5.1	6.9	3.4	1.5	11.9
Piedmont	0.0	0.0	0.0	2.3	2.3	1.3	1.3	6.0	8.5
Chambers (1)	3.4	0.0	3.2	0.0	6.6	0.0	5.9	0.0	5.9
Orlando (1)	1.6	7.2	9.6	9.4	27.8	2.6	9.7	6.4	18.6
Selkirk (1)(2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**16.3**	**22.8**	**21.3**	**26.5**	**86.9**	**21.8**	**35.0**	**17.5**	**$74.3**
West U.S.									
Manchief	1.9	1.0	4.2	2.8	9.9	3.2	0.6	4.2	8.0
Naval Station	1.5	1.7	4.0	1.7	8.8	1.2	(0.7)	(0.4)	0.0
Naval Training Center	0.8	0.7	2.2	1.1	4.8	0.8	(0.5)	(0.4)	(0.0)
North Island	1.4	1.3	3.4	2.0	8.1	1.4	(0.7)	(0.4)	0.3
Oxnard	(0.3)	(1.4)	(2.0)	7.6	3.9	(0.2)	(0.2)	5.3	4.9
Frederickson (1)	1.9	3.2	2.4	3.1	10.5	4.0	3.0	3.4	10.4
Koma Kulshan (3)	0.3	0.0	0.5	0.0	0.8	0.6	0.1	0.4	1.1
Total	**7.6**	**6.4**	**14.5**	**18.3**	**46.8**	**11.0**	**1.8**	**12.0**	**24.7**
Canada									
Calstock	0.7	1.6	0.0	1.7	3.9	2.9	1.8	(0.1)	4.7
Kapuskasing	6.7	14.9	6.0	4.7	32.4	6.3	(0.2)	(0.1)	6.0
Mamquam	0.5	1.5	2.3	0.9	5.2	1.9	2.7	2.6	7.2
Moresby Lake	0.3	(0.3)	0.1	0.3	0.4	0.6	(0.1)	(0.2)	0.3
Nipigon	5.5	4.8	4.3	2.9	17.5	10.0	5.7	2.4	18.1
North Bay	7.1	14.5	5.3	4.0	30.8	6.6	(0.1)	(0.1)	6.4
Tunis	(0.7)	6.6	(0.2)	(1.6)	4.2	(0.5)	(3.1)	(0.5)	(4.1)
Williams Lake	2.4	2.1	6.5	3.8	14.8	4.0	1.2	(0.9)	4.2
Total	**22.4**	**45.7**	**24.3**	**16.7**	**109.1**	**31.7**	**8.0**	**3.2**	**42.9**
Total Cash Distributions	**$46.2**	**$75.0**	**$60.2**	**$61.4**	**$242.8**	**$64.5**	**$44.7**	**$32.8**	**$141.9**
Consolidated	39.0	64.7	44.5	48.9	197.1	57.4	26.0	23.0	106.3
Equity Method	7.2	10.3	15.7	12.5	45.7	7.1	18.8	9.8	35.7

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates. (2) Project sold in November 2017. (3) Consolidated as of July 27, 2018; equity investment prior to that date. For purpose of Q3, is included in the Consolidated subtotal.

Non-GAAP Disclosures

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. Investors are cautioned that the Company may calculate this non-GAAP measure in a manner that is different from other companies. The most directly comparable GAAP measure is Project income (loss). Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in the fair value of derivative instruments. Management uses Project Adjusted EBITDA at the project level to provide comparative information about project performance and believes such information is helpful to investors. A reconciliation of Project Adjusted EBITDA to Project income (loss) and to Net income (loss) by segment and on a consolidated basis is provided on page 33-34.

Investors are cautioned that the Company may calculate these measures in a manner that is different from other companies.

$ millions, unaudited	**Three months ended September 30,**		**Nine months ended September 30,**	
	2018	**2017**	**2018**	**2017**
Net (loss) income attributable to Atlantic Power Corporation	**($3.2)**	**($32.9)**	**$12.1**	**($57.5)**
Net (loss) income attributable to preferred share dividends of a subsidiary company	(1.5)	(0.8)	(1.6)	3.5
Net (loss) income	**($4.7)**	**($33.7)**	**$10.5**	**($54.0)**
Income tax expense (benefit)	3.6	(15.9)	7.7	(38.5)
(Loss) income from operations before income taxes	(1.1)	(49.6)	18.2	(92.5)
Administration	5.7	5.5	17.9	17.6
Interest expense, net	14.6	13.8	40.7	49.5
Foreign exchange loss (gain)	4.5	9.4	(9.1)	17.7
Other expense, net	2.5	-	0.3	-
Project income (loss)	**$26.2**	**($20.9)**	**$68.0**	**($7.7)**
Reconciliation to Project Adjusted EBITDA				
Depreciation and amortization	$25.0	$36.6	$78.0	$105.6
Interest, net	(0.6)	2.5	2.7	8.0
Change in the fair value of derivative instruments	-	2.0	(3.5)	5.8
Impairment	-	57.3	-	57.3
Other project (income) expense	(5.2)	(0.1)	(6.7)	57.6
Project Adjusted EBITDA	**$45.4**	**$77.4**	**$138.5**	**$226.6**

Reconciliation of Net Income (Loss) to Project Adjusted EBITDA by Segment, Q3 2018 vs Q3 2017

($ millions)

Three months ended September 30, 2018

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net income (loss) attributable to Atlantic Power Corporation	$12.7	$12.6	$1.2	($29.7)	($3.2)
Net loss attributable to preferred share dividends of a subsidiary company	-	-	-	(1.5)	(1.5)
Net income (loss)	12.7	12.6	1.2	(31.2)	(4.7)
Income tax expense	-	-	-	3.6	3.6
Income (loss) before income taxes	12.7	12.6	1.2	(27.6)	(1.1)
Administration	-	-	-	5.7	5.7
Interest expense, net	-	-	-	14.6	14.6
Foreign exchange loss	-	-	-	4.5	4.5
Other expense, net	-	-	-	2.5	2.5
Project Income	12.7	12.6	1.2	(0.3)	26.2
Change in fair value of derivative instruments	0.5	-	(0.8)	0.3	-
Depreciation and amortization	11.6	5.5	7.9	-	25.0
Interest, net	0.7	(1.3)	-	-	(0.6)
Other project (income) expense	-	(5.3)	-	0.1	(5.2)
Project Adjusted EBITDA	$25.5	$11.5	$8.3	$0.1	$45.4

Three months ended September 30, 2017

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net income (loss) attributable to Atlantic Power Corporation	$15.0	($46.2)	$9.4	($11.1)	($32.9)
Net loss attributable to preferred share dividends of a subsidiary company	-	-	-	(0.8)	(0.8)
Net income (loss)	15.0	(46.2)	9.4	(11.9)	(33.7)
Income tax benefit	-	-	-	(15.9)	(15.9)
Income (loss) before income taxes	15.0	(46.2)	9.4	(27.8)	(49.6)
Administration	-	-	-	5.5	5.5
Interest expense, net	-	-	-	13.8	13.8
Foreign exchange loss	-	-	-	9.4	9.4
Project income (loss)	15.0	(46.2)	9.4	0.9	(20.9)
Change in fair value of derivative instruments	1.3	-	1.3	(0.6)	2.0
Depreciation and amortization	11.8	10.6	14.0	0.2	36.6
Interest, net	2.5	-	-	-	2.5
Impairment	-	57.3	-	-	57.3
Other project income	-	-	(0.1)	-	(0.1)
Project Adjusted EBITDA	$30.6	$21.7	$24.6	$0.5	$77.4

Reconciliation of Net Income (Loss) to Project Adjusted EBITDA by Segment, YTD Sept 2018 vs YTD Sept 2017

($ millions)

Nine months ended September 30, 2018

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net income (loss) attributable to Atlantic Power Corporation	$51.5	$4.4	$9.8	($53.6)	$12.1
Net loss attributable to preferred share dividends of a subsidiary company	-	-	-	(1.6)	(1.6)
Net income (loss)	51.5	4.4	9.8	(55.2)	10.5
Income tax expense	-	-	-	7.7	7.7
Net income (loss) before income taxes	51.5	4.4	9.8	(47.5)	18.2
Administration	-	-	-	17.9	17.9
Interest expense, net	-	-	-	40.7	40.7
Foreign exchange gain	-	-	-	(9.1)	(9.1)
Other expense, net	-	-	-	0.3	0.3
Project income	51.5	4.4	9.8	2.3	68.0
Change in fair value of derivative instruments	0.8	-	(2.2)	(2.1)	(3.5)
Depreciation and amortization	34.8	19.2	23.9	0.1	78.0
Interest, net	2.7	-	-	-	2.7
Other project income	-	(6.7)	-	-	(6.7)
Project Adjusted EBITDA	$89.8	$16.9	$31.5	$0.3	$138.5

Nine months ended September 30, 2017

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net (loss) income attributable to Atlantic Power Corporation	($16.4)	($46.4)	$51.6	($46.3)	($57.5)
Net income attributable to preferred share dividends of a subsidiary company	-	-	-	3.5	3.5
Net (loss) income	(16.4)	(46.4)	51.6	(42.8)	(54.0)
Income tax benefit	-	-	-	(38.5)	(38.5)
Net (loss) income before income taxes	(16.4)	(46.4)	51.6	(81.3)	(92.5)
Administration	-	-	-	17.6	17.6
Interest expense, net	-	-	-	49.5	49.5
Foreign exchange loss	-	-	-	17.7	17.7
Project (loss) income	(16.4)	(46.4)	51.6	3.5	(7.7)
Change in fair value of derivative instruments	3.3	-	5.4	(2.9)	5.8
Depreciation and amortization	34.2	30.6	40.4	0.4	105.6
Interest, net	8.0	-	-	-	8.0
Impairment	-	57.3	-	-	57.3
Other project expense (income)	57.7	-	(0.1)	-	57.6
Project Adjusted EBITDA	$86.8	$41.5	$97.3	$1.0	$226.6