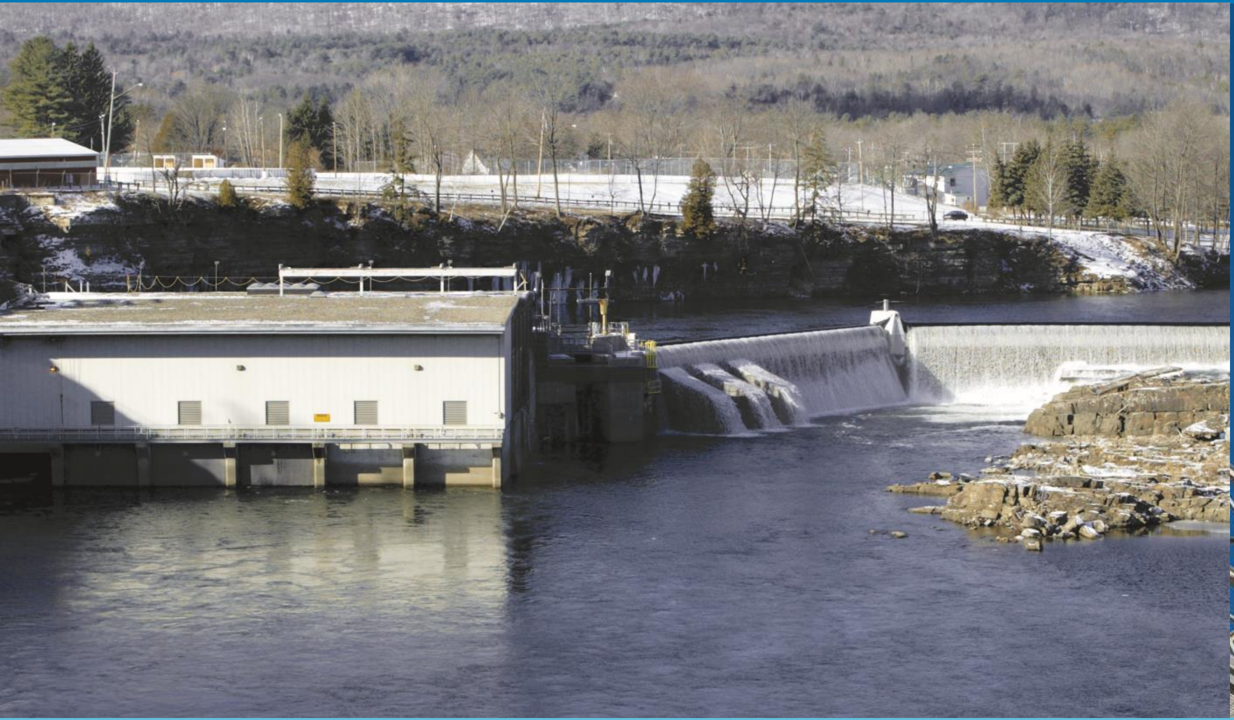
AtlanticPower Corporation



Q2 2018 Financial Results Conference Call

August 3, 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 page 34.

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

Agenda

Q2 2018

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

Q2 2018 Highlights

Financial Results on Track	• Second quarter results modestly better than expected, though below year-ago levels • First half results keep us on track to achieve our full year 2018 expectations
Strengthening Balance Sheet	• On track to repay $100 million of debt for full year 2018 • Leverage ratio 3.8 times at June 30, 2018; expected higher by YE 2018, but lower in 2019 and beyond • Liquidity of $203.4 million at June 30, 2018, including ~ $42 million of discretionary cash
Balanced Capital Allocation	• Repurchased and canceled $4.6 million of common and preferred shares in Q2/July 2018, $14.9 million YTD July 2018 - Average price $2.14 per common share - Returns of 10-11% on repurchases of preferred shares • Acquired partners' ownership interests in Koma Kulshan for $13.2 million - ~10x estimated pro forma Project Adjusted EBITDA - ~11x estimated pro forma cash distributions
Operational and Commercial	• Manchief: Returned from gas turbine overhaul • Tunis: Re-start under PPA delayed to October 2018 • Williams Lake: Reducing operations and maintenance costs • San Diego: Unlikely to achieve site control; preparing to decommission

Mitigating the Financial Impact of Expiring PPAs

Timing of PPA expirations is lumpy

- **2018 relative to 2017**:
  - Six PPAs expired[1]: ~$83 million
  - OEFC settlement: ~$29 million

  Total reduction to 2018 EBITDA: ~$112 million
- **2019**: Two (Williams Lake, Kenilworth); **2020**: Two (Oxnard, Calstock); **2021**: None
  - The four PPAs expiring in 2019 – 2021 are modest in terms of annual EBITDA contribution (~$15 million)
- Approximately two-thirds of 2018 Project Adjusted EBITDA is from projects with PPAs expiring after 2022

Significant delevering expected to occur during this period

- Existing projects / PPAs produce significant cash flow excess to their needs (i.e., make distributions to parent)
  - Majority of operating cash flow will be applied to pay down term loan
- Expect to reduce total debt by more than half by YE 2022 (~$400 million vs $821 million at 6/30/18)
- Leverage ratio should decline in 2019 and beyond
  - Debt reduction expected to be more significant than impact of EBITDA declines due to expiring PPAs
- Lower debt level results in lower cash interest payments
  - Thus, impact of PPA expirations is less on operating cash flow than on EBITDA

Improved debt maturity profile

- Only bullet maturity through YE 2022 is $19 million (US$ equivalent) Series D convertible debentures (Dec. 2019)

Leaner corporate structure

- Reduced corporate overheads by ~60% since 2013, to an estimated $22 million in 2018
- Continuing to identify additional areas of cost savings (modest)

(1) Six PPAs expired between 12/31/2017 – 4/1/2018: Kapuskasing, North Bay, Naval Station, North Island, NTC and Williams Lake

Progress on Commercial Initiatives

Ontario

- Short-term enhanced dispatch contracts (Kapuskasing, North Bay and Nipigon)
- OEFC Settlement (Kapuskasing, North Bay and Tunis); significantly accretive in 2017
- Long-term enhanced dispatch contract (Nipigon); reduced operating risk
- New 15-year PPA (to 2033) for Tunis in difficult market; expect to re-start in October 2018

San Diego

- New seven-year contracts for Naval Station and North Island
  - Strong implied returns on incremental investment
  - Unlikely to proceed due to lack of site control with Navy; preparing to decommission
- Eliminated risk of early termination penalties under original PPAs

Williams Lake

- Short-term extension; less favorable economics but bridge to a potential long-term PPA

Morris

- 11-year extension (to 2034) on comparable terms

Piedmont

- Achieved operational turnaround and gained operating flexibility
- Now a debt-free plant with a PPA that runs through 2032

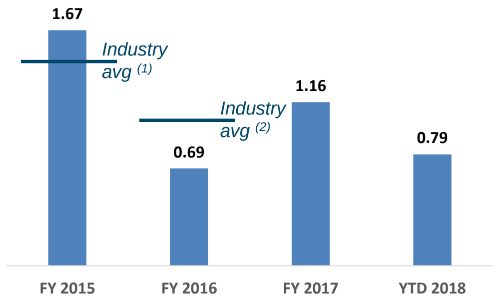
Koma Kulshan

- Consolidated ownership of small hydro at attractive valuation (~11x estimated cash distributions)
- Longest-dated PPA (2037)

Q2 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*

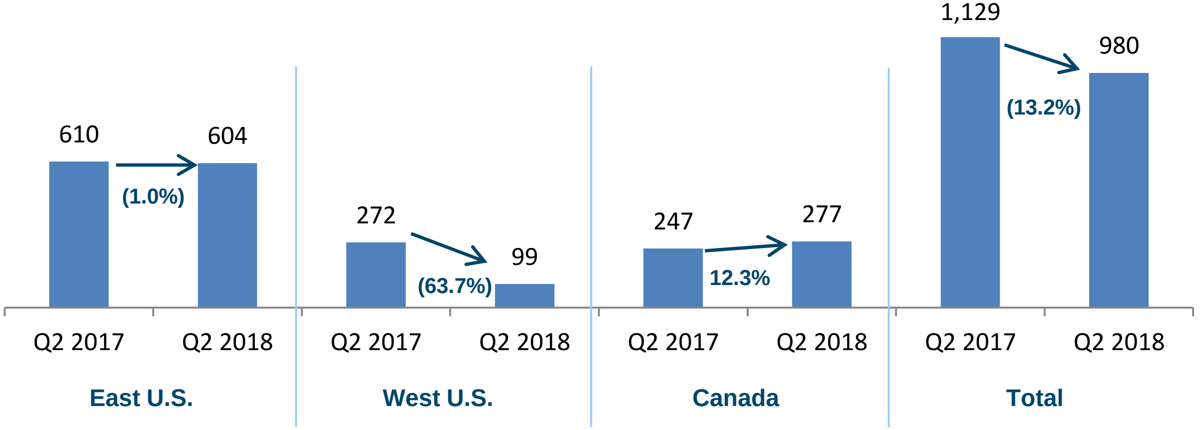
Availability (weighted average)

	Q2 2018	Q2 2017
East U.S.	95.3%	86.7%
West U.S.	85.2%	72.0%
Canada	96.4%	87.0%
Total	**93.4%**	**83.6%**

Higher availability factor:

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

Aggregate Power Generation Q2 2018 vs. Q2 2017 (Net GWh)



Generation is down:

− Naval Station / North Island / NTC ceased operations in February 2018
− Curtis Palmer lower water flows
+ Orlando shorter spring maintenance outage this year
+ Mamquam higher water flows, forced outage in prior period
+ Manchief higher dispatch
+ Kenilworth maintenance outage in prior period

Hydro generation

Curtis Palmer	Mamquam
-28% vs Q2 2017	+35% vs Q2 2017
-7% vs long-term avg.	+22% vs long-term avg.

Operations Update

Tunis Planned Re-start

- Work completed on gas turbine overhaul, generator overhaul and upgrade and testing of controls system; commissioning of plant completed
- Estimated cost at the low end of $5 - $6 million range; majority was incurred in the first six months of 2018
- Independent engineer filed commissioning report with IESO on July 30, 2018; review typically takes ~60 days
- To complete capacity test (expected 40 MW) and other tests in late August
- Targeting re-start under PPA in October 2018

Nipigon Long-term Enhanced Dispatch Contract

- Expected return to service November 1, 2018 under LTEDC (through Dec. 2022)
  - To return in simple-cycle mode and operate 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

Significant 2018 Outages

- Manchief – GT11 overhaul completed in late May
- Kenilworth – Gas turbine overhaul expected to be completed in early September; continuing to operate on lease engine
- Mamquam – Runner replacements deferred to Q1 2019

Analysis & Benchmarking for Cost Savings

- Internal benchmarking of plants completed
- Retained consulting firm to do external benchmarking for thermal plants; expect report in Q4
- VP to head up effort, focused solely on this program

Williams Lake

- Reducing operations and maintenance expense to mitigate impact of higher fuel costs and short-term PPA

Koma Kulshan

- Assumed operations on July 27, 2018

Commercial Update

Naval Station, North Island and NTC (San Diego)

- Remain engaged with Navy regarding potential paths to site control at Naval Station and North Island
  - Probability of success remains low; continuing preparations to decommission both sites
- No path to site control at NTC
  - Contract with SCE was recently rejected by the CPUC
  - Intend to proceed with decommissioning of the site
- In the process of determining, together with the Navy, the scope and timing of decommissioning work for all three sites

Williams Lake (British Columbia)

- Short-term contract extension runs from April 2, 2018 to June 30, 2019 (or Sept. 30, 2019 at BC Hydro's option)
- Extension is subject to approval of BC Utilities Commission
  - Proceeding commenced in late April
  - Schedule was recently extended
  - Either party has right to terminate if contract does not receive regulatory approval by September 17, 2018
- Written hearing regarding appeal of amended air permit (to burn alternative fuels) currently underway
  - Decision expected in Q4 2018

Q2 2018 Financial Highlights

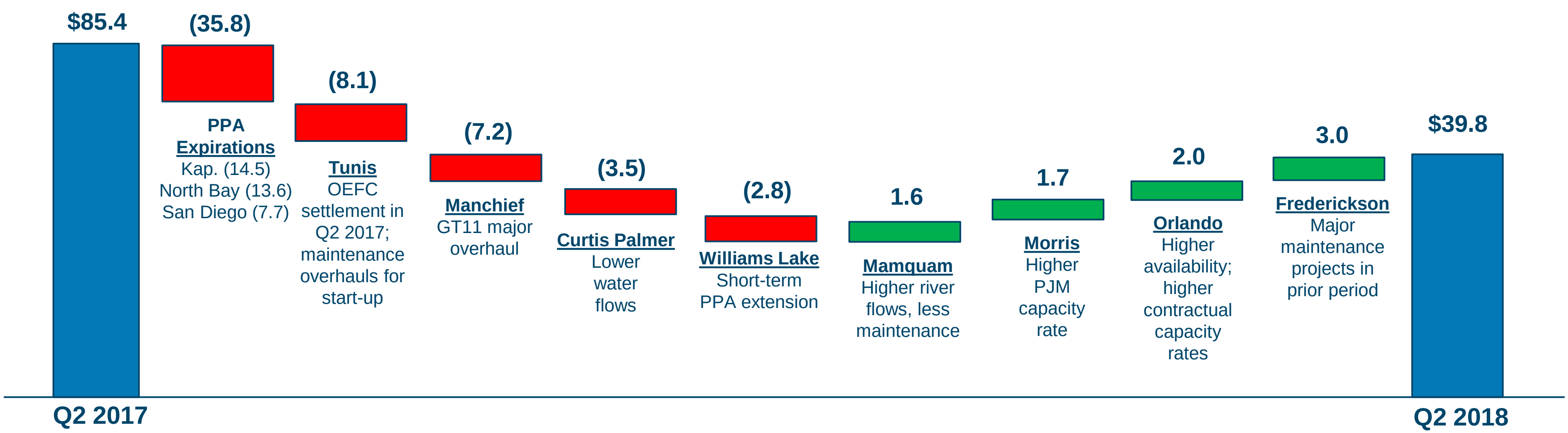
Q2 2018 Financial Results	**Project Adjusted EBITDA** **Q2 2018 $39.8 million vs Q2 2017 $85.4 million** (see bridge on page 12) • Results better than anticipated (Morris, Mamquam, Kenilworth; partially offset by Curtis Palmer) • Some maintenance expense shifted from 1H 2018 to 2H 2018 • On track for full year 2018 guidance ($170 to $185 million) **Cash Provided by Operating Activities** **Q2 2018 $28.1 million vs Q2 2017 $51.6 million** (see bridge on page 14) • Working capital benefit related to PPA expirations/plant shutdowns • Not assumed in 2018 estimate of $95 to $110 million (page 19)
Continued Debt Repayment	• Amortized $20 million of term loan and $6.4 million of project debt in Q2 2018 • Consolidated leverage ratio at 6/30/18 of 3.8 times • Liquidity at 6/30/18 of $203.4 million, including ~ $42 million of discretionary cash

Q2 2018 Financial Highlights (continued)

Managing Interest Costs and Risk	• Exposure to higher interest rates is modest - At 6/30/18, ~ 96.1% of our debt was fixed rate or swapped - ~$300 thousand impact in remainder 2018 and ~$450 thousand in 2019, per 100 bp change in rates
NCIB Update	**Q2 2018: Shares repurchased and canceled** • 1.3 million common shares at average price of $2.14/share - Total cost $2.8 million • 40,000 Series 3 preferred shares at Cdn$18.00/share - Total cost Cdn$0.7 million ($0.6 million US$ equivalent) **July 2018: Shares repurchased and canceled** • 0.3 million common shares at average price $2.14/share - Total cost $0.6 million • 5,000 Series 2 preferred shares at Cdn$17.99/share • 41,965 Series 3 preferred shares at Cdn$17.95/share - Total cost Cdn$0.8 million ($0.6 million US$ equivalent)

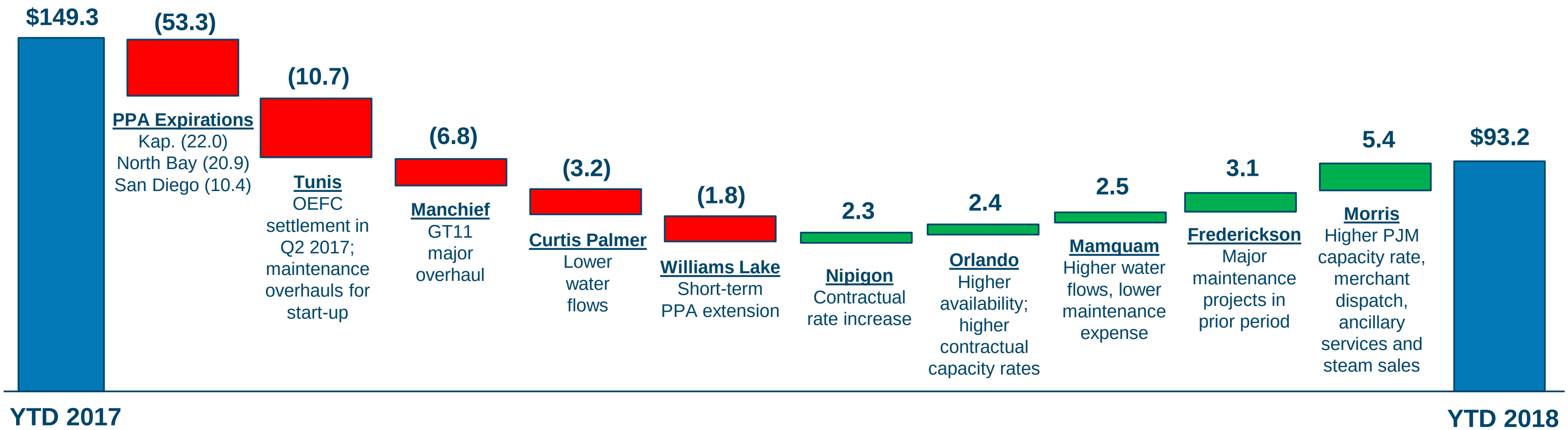
Q2 2018 Project Adjusted EBITDA (bridge vs 2017)

($ millions)



YTD June 2018 Project Adjusted EBITDA (bridge vs 2017)

($ millions)



Q2 and YTD June 2018 Cash Flow Results

($ millions)

	Three months ended June 30,		
Unaudited	**2018**	**2017**	**Change**
Cash provided by operating activities	$28.1	$51.6	$(23.5)
Significant uses of cash provided by operating activities:			
Term loan repayments [(1)]	(20.0)	(27.1)	7.1
Project debt amortization	(6.4)	(2.4)	4.0
Capital expenditures	(0.1)	(2.2)	2.1
Preferred dividends	(2.1)	(2.2)	0.1

Primary drivers:
- Lower Project Adjusted EBITDA -45.6
- Changes in working capital (primarily related to five PPA expirations) +13.8
- Lower cash interest payments +8.7

	Six months ended June 30,		
Unaudited	**2018**	**2017**	**Change**
Cash provided by operating activities	$78.4	$85.7	$(7.3)
Significant uses of cash provided by operating activities:			
Term loan repayments [(1)]	(50.0)	(52.2)	2.2
Project debt amortization	(8.8)	(4.7)	(4.0)
Capital expenditures	(0.3)	(4.2)	3.9
Preferred dividends	(4.3)	(4.3)	-

Primary drivers:
- Lower Project Adjusted EBITDA -56.1
- Changes in working capital (primarily related to five PPA expirations) +34.7
- Lower cash interest payments +13.2

(1) Includes 1% mandatory annual amortization and targeted debt repayments.

Liquidity

($ millions)

	Jun 30, 2018	Mar 31, 2018
Cash and cash equivalents, parent	$49.2	$39.2
Cash and cash equivalents, projects	31.6	43.4
Total cash and cash equivalents	**80.8**	**82.6**
Revolving credit facility	200.0	200.0
Letters of credit outstanding	(77.4)	(77.5)
Availability under revolving credit facility	**122.6**	**122.5**
Total Liquidity	**$203.4**	**$205.1**
Excludes restricted cash of:	$1.9	$5.7

Consolidated debt [(1)]	**$778.1**	**$810.2**
Leverage ratio [(2)]	**3.8**	**3.2**

Release of cash by the projects due to lower working capital needs (five PPAs terminated/projects not in operation)

In Q2 2018, we used discretionary cash of $3.4 million for the repurchase of common and preferred shares and $1.1 million for an additional equity investment in the Koma Kulshan hydro project.

[(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 June 30, 2018 (1)

($ millions)

Total $821 — 55% amortizing, 45% bullet (2)

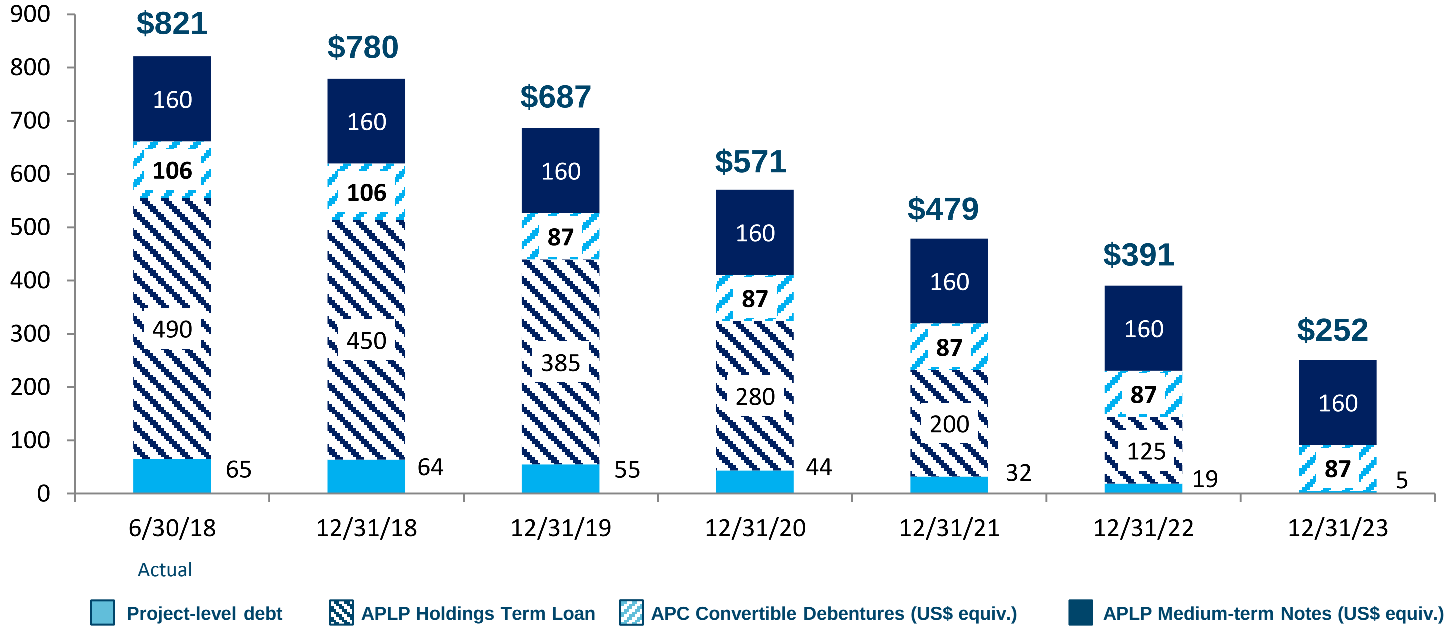
- Project-level non-recourse debt totals $65, including $43 at Chambers (equity method); amortizes over the life of the project PPAs (through 2025)
- $490 amortizing term loan (maturing in April 2023), which has 1% annual amortization and mandatory prepayment via the greater of a 50% sweep or such other amount that is required to achieve a specified targeted debt balance (combined average annual repayment of ~ $83)
- $19 (US$ equivalent) of Series D and $87 (US$ equivalent) of Series E convertible debentures (maturing in Dec 2019 and Jan 2025, respectively)
- $160 (US$ 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 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 $1.3168.

Projected Debt Balances through 2023 [1]

($ millions)



<u>Expected Debt Repayment (June 30, 2018 – Year-end 2023):</u>

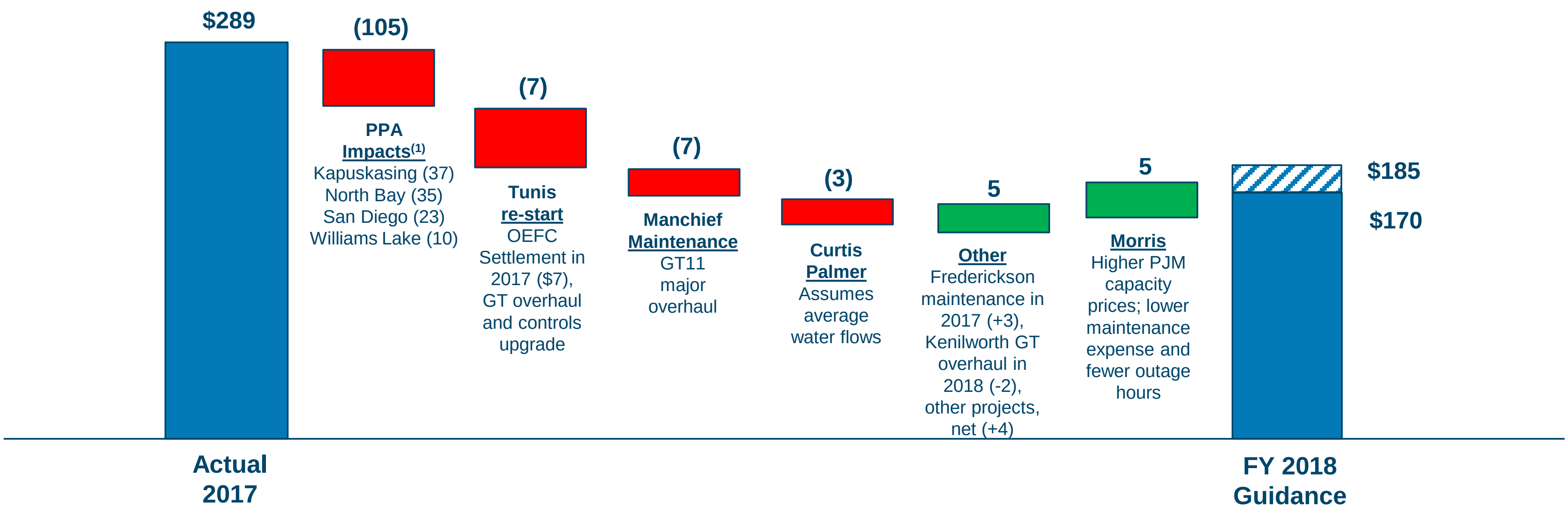
- Term loan – Amortize $365; $125 remaining balance due at maturity in April 2023 [2]
- Project debt (proportional) – Repay $60, ending balance $5
- Series D convertible debentures mature Dec. 2019 ($19 US$ equivalent)

[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 $1.3168.

2018 Project Adjusted EBITDA Guidance (bridge vs 2017)

($ millions)

No change to 2018 guidance range



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) Expirations at Kapuskasing and North Bay, early terminations in San Diego (three projects), short-term extension on less favorable terms at Williams Lake; includes impact of OEFC settlement revenues in 2017 for Kapuskasing and North Bay.

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 ~$1

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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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 and beyond	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
	Piedmont	Georgia	Biomass	100%	55	9/2032
	Tunis	Ontario	Nat. Gas	100%	40	(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 expected to commence in Q3 2018. (8) Equistar has an option to purchase Morris that is exercisable in December 2020 and December 2027.

Capitalization

($ millions)

	June 30, 2018		Dec. 31, 2017	
Long-term debt, incl. current portion [1]				
APLP Medium-Term Notes [2]	$159.5		$167.4	
Revolving credit facility	-		-	
Term Loan	490.0		540.0	
Project-level debt (non-recourse)	22.5		31.2	
Convertible debentures [2]	106.1		107.0	
Total long-term debt, incl. current portion	**$778.1**	**80%**	**$845.5**	**79%**
Preferred shares [3]	206.3	21%	215.2	18%
Common equity [4]	(18.4)	(1)%	(18.4)	2%
Total shareholders equity	**$187.9**	**20%**	**$196.8**	**21%**
Total capitalization	**$966.0**	**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 $159 million and $175 million at June 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 June 30, 2018

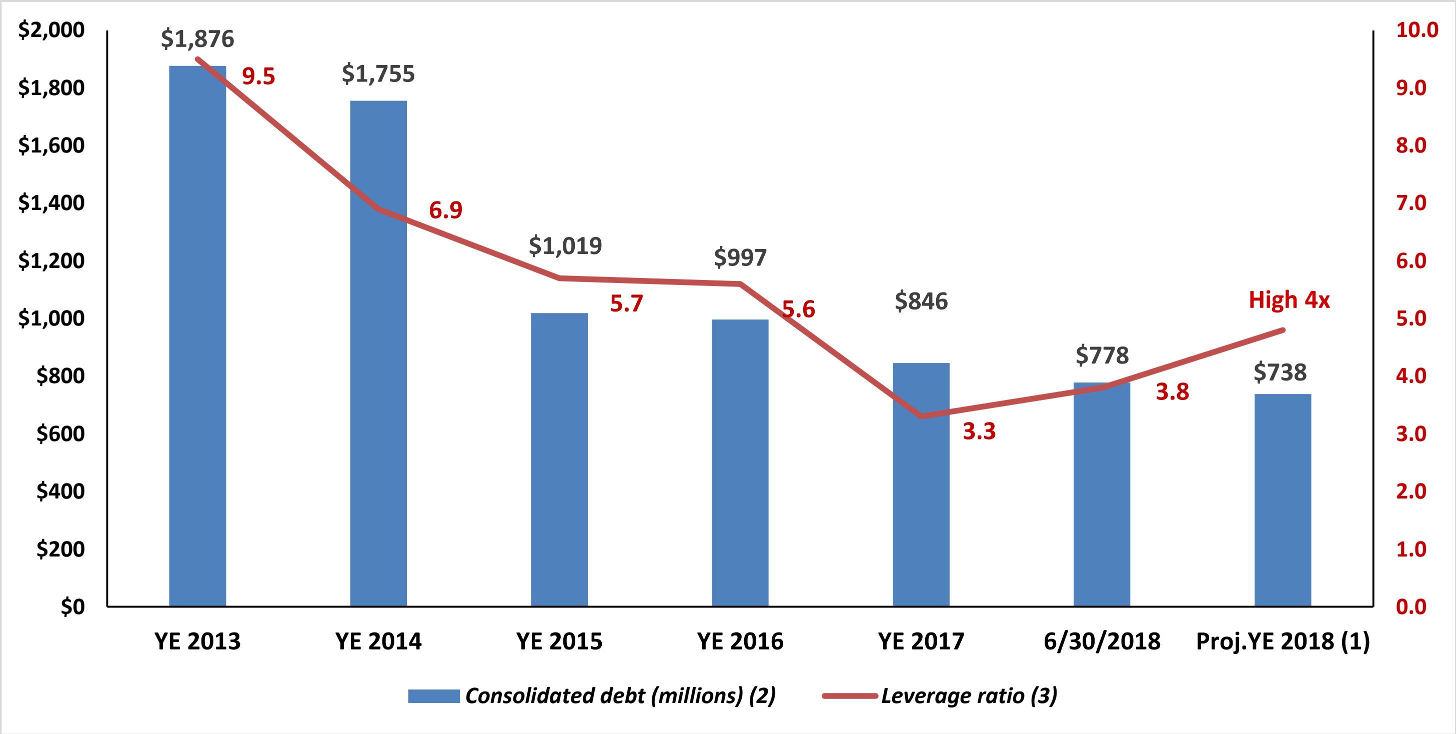
($ millions)

Atlantic Power Corporation			
	Maturity	**Amount**	**Interest Rate**
Convertible Debentures (ATP.DB.D)	12/2019	$18.8 (C$24.7)	6.00%
Convertible Debentures (ATP.DB.E)	1/2025	$87.3 (C$115.0)	6.00%
APLP Holdings Limited Partnership			
	Maturity	**Amount**	**Interest Rate**
Revolving Credit Facility	4/2022	$0	LIBOR + 3.00%
Term Loan	4/2023	$490.0	3.87%-5.42% (1)
Atlantic Power Limited Partnership			
	Maturity	**Amount**	**Interest Rate**
Medium-term Notes	6/2036	$159.5 (C$210)	5.95%
Preferred shares (AZP.PR.A)	N/A	$85.7 (C$112.8)	4.85%
Preferred shares (AZP.PR.B)	N/A	$44.4 (C$58.5)	5.57%
Preferred shares (AZP.PR.C)	N/A	$29.2 (C$38.5)	5.28% (2)
Atlantic Power Transmission & Atlantic Power Generation			
	Maturity	**Amount**	**Interest**
Project-level Debt (consolidated)	Various	$22.5	6.14%-6.38%
Project-level Debt (equity method)	Various	$42.9	4.50%-5.00%

(1) Weighted average rate at 6/30/18 of 4.38%. Range and weighted average include impact of interest rate swaps. (2) Set on March 1, 2017 for June 29, 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 $1.3168.

Strengthening Balance Sheet

($ millions)



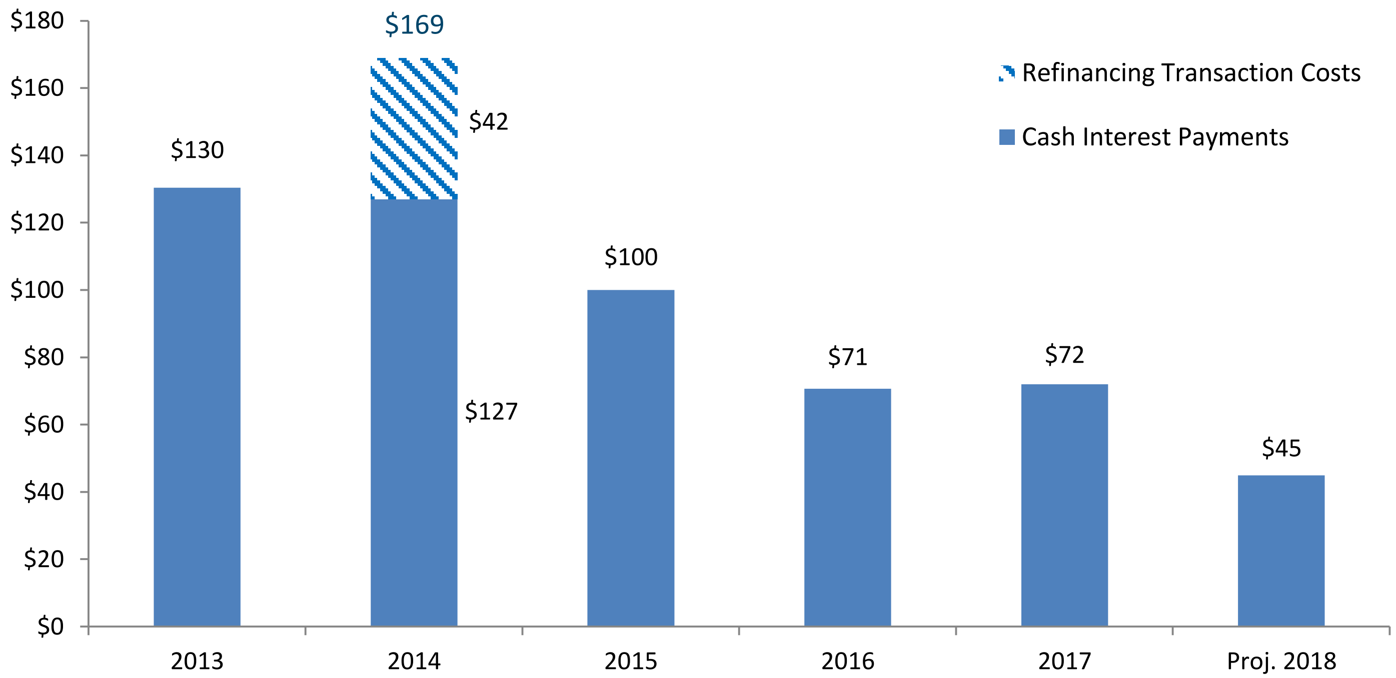
Total net reduction in consolidated debt since YE 2013 of more than <u>$1.1 billion</u>

- **Expect to repay another ~$42 million of debt by YE 2018, for a total of approximately $100 million in 2018**
- **Leverage ratio expected to move higher by YE 2018 (due to lower Projected Adjusted EBITDA), but we expect continuing debt repayment to move it lower in 2019**

(1) Assumes $100 million of debt repayments in 2018
(2) Excludes unamortized discounts and deferred financing costs
(3) See page 28 of this presentation for definition

Reducing Cash Interest Payments [1]

($ millions)

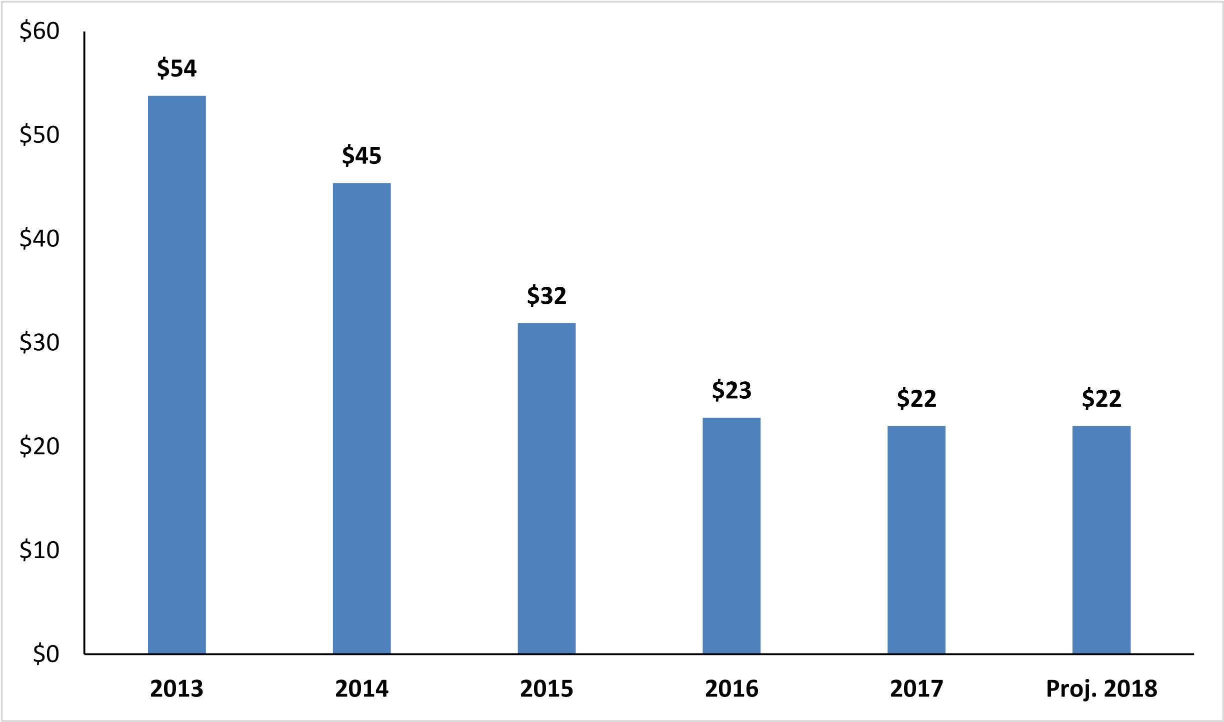


- **Reduction has been driven by debt repayment as well as re-pricings of our term loan and revolver**
- **Re-priced facilities three times, to 300 basis points over LIBOR (had been 500); these re-pricings will save $41 million over the remaining terms of the facilities**

[1] Consolidated debt only

Reduced Corporate Overheads

($ millions)



General and Administrative Expenses + Development Expenses

Approximate 60% reduction from 2013 level

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
6/30/2018	5.00:1.00	3.00:1.00
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.

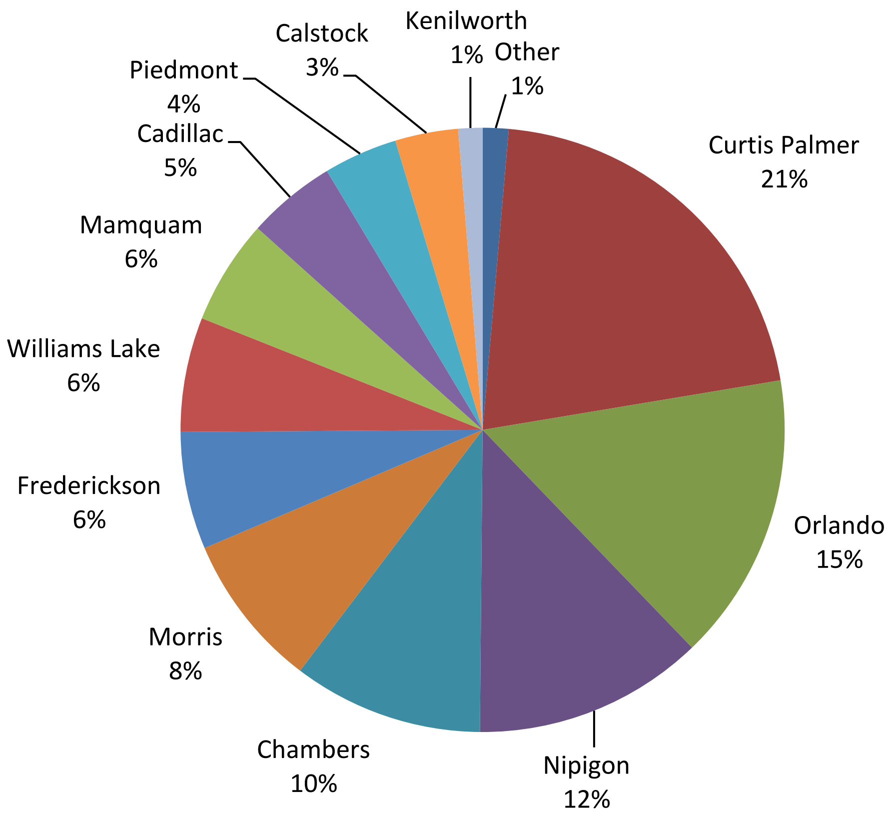
Consolidated cash interest payments include interest payments on the debt included in the Consolidated debt ratio defined above.

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

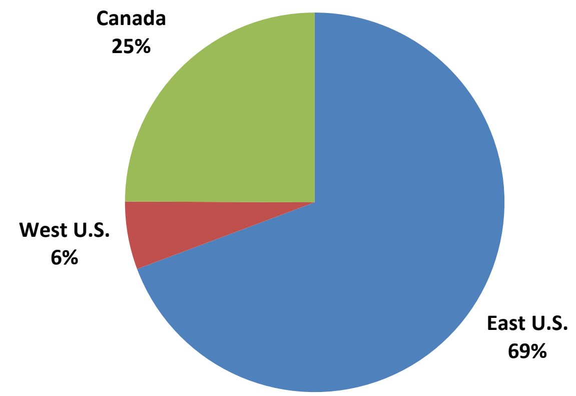
Project Adjusted EBITDA by Project – Six months ended June 30, 2018

Curtis Palmer is the single largest contributor (21%); next eight projects account for ~70%



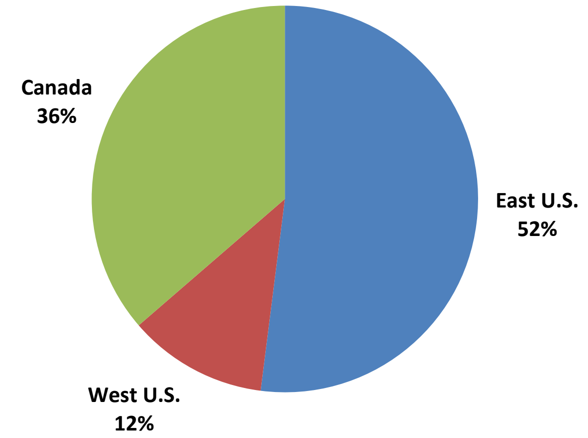
Six months ended June 30, 2018

Project Adjusted EBITDA by Segment [1]



Six months ended June 30, 2018

Cash Distributions from Projects by Segment [2]



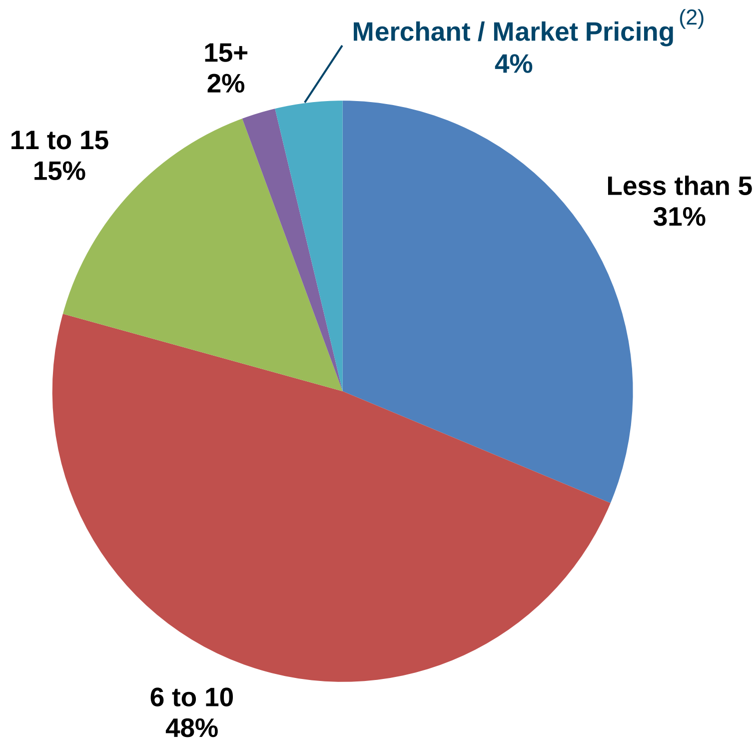
[1] Based on Project Adjusted EBITDA for the six months ended June 30, 2018, excluding non-operational and two other projects that have negative Project Adjusted EBITDA for the period. Un-allocated corporate segment is included in "Other" category for project percentage allocation and allocated equally among segments for six months ended June 30, 2018 Project Adjusted EBITDA by Segment.

[2] Based on $109.2 million in Cash Distributions from Projects for the six months ended June 30, 2018.

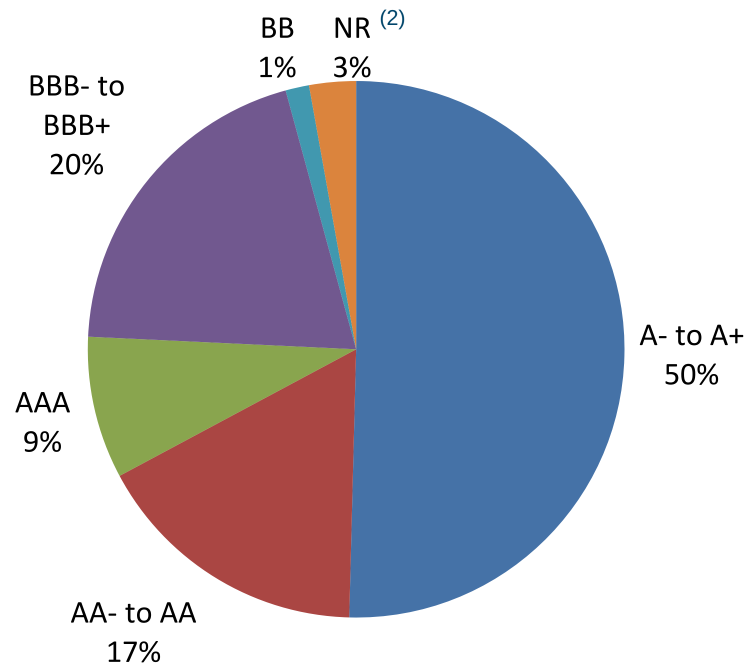
Majority of Cash Flows Covered by Contracts with More Than 5 Years Remaining

Contracted projects have an average remaining PPA life of 6.5 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, Q2 and YTD June 2018 vs Q2 and YTD June 2017

($ millions, unaudited)

Summary of Financial and Operating Results

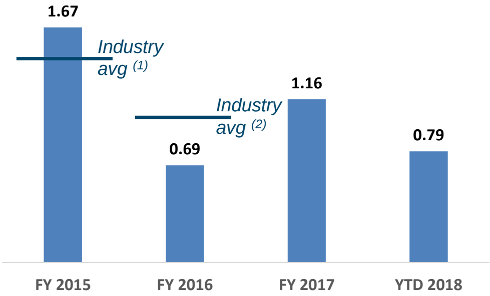
	Three months ended June 30		Six months ended June 30,	
	2018	**2017**	**2018**	**2017**
Financial Results				
Project revenue	$66.2	$124.0	$146.2	$222.4
Project income	13.6	(12.1)	41.8	13.2
Net (loss) income attributable to Atlantic Power Corp.	(0.6)	(21.9)	15.2	(24.6)
Cash provided by operating activities	28.1	51.6	78.4	85.7
Project Adjusted EBITDA	39.8	85.4	93.2	149.3
Operating Results				
Aggregate power generation (net GWh)	979.9	1,128.9	2,100.5	2,281.5
Weighted average availability	93.4%	83.6%	96.0%	89.9%

Segment Results

	Three months ended June 30,		Six months ended June 30,	
	2018	**2017**	**2018**	**2017**
Project income (loss)				
East U.S.	$18.4	($43.3)	$39.1	($30.8)
West U.S.	(6.3)	0.7	(8.2)	-
Canada	1.2	31.1	8.5	42.3
Un-allocated Corporate	0.3	(0.6)	2.4	1.7
Total	**13.6**	**(12.1)**	**41.8**	**13.2**
Project Adjusted EBITDA				
East U.S.	$31.2	$29.1	$64.4	$56.2
West U.S.	(0.7)	10.6	5.4	19.8
Canada	9.0	45.2	23.2	72.8
Un-allocated Corporate	0.3	0.5	0.2	0.5
Total	**39.8**	**85.4**	**93.2**	**149.3**

YTD June 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*

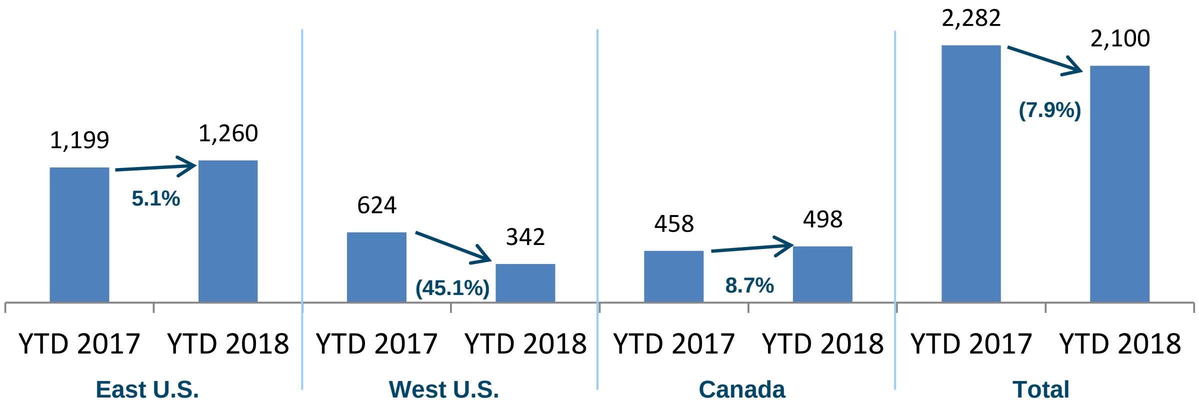
Availability (weighted average)

	YTD 2018	YTD 2017
East U.S.	96.7%	91.7%
West U.S.	93.3%	85.3%
Canada	98.1%	88.9%
Total	**96.0%**	**89.9%**

Higher availability factor:

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

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



Generation is down:

− Naval Station / North Island / NTC ceased operations in February 2018
− Fredrickson lower demand (milder temperatures)
− Curtis Palmer lower water flows
+ 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
-16% vs YTD June 2017	+29% vs YTD June 2017
+1% vs long-term avg.	+22% vs long-term avg.

Project Income (Loss) by Project, Q2 and YTD June 2018 vs Q2 and YTD June 2017

($ millions)

	Three months ended June 30		Six months ended June 30	
	2018	2017	2018	2017
East U.S.				
Cadillac	$1.5	$1.4	$2.1	$1.8
Curtis Palmer	5.8	9.2	13.1	16.2
Kenilworth	(0.4)	(0.7)	(0.1)	(0.6)
Morris	2.2	0.5	4.7	0.7
Piedmont	0.8	(1.3)	0.2	(3.2)
Chambers (1)	1.7	(46.5)	4.8	(43.9)
Orlando (1)	6.8	5.0	14.3	9.8
Selkirk (1) (2)	-	(10.9)	-	(11.6)
Total	**18.4**	**(43.3)**	**39.1**	**(30.8)**
West U.S.				
Manchief	(6.7)	0.5	(5.8)	1.1
Naval Station	(0.5)	1.1	(1.2)	0.8
Naval Training Center	(0.4)	0.9	(1.1)	0.6
North Island	(0.4)	1.0	(1.0)	1.3
Oxnard	(0.2)	(0.5)	(2.8)	(2.5)
Frederickson (1)	1.3	(2.7)	3.2	(1.9)
Koma Kulshan (1)	0.6	0.5	0.5	0.6
Total	**(6.3)**	**0.7**	**(8.2)**	**-**
Canada				
Calstock	1.0	0.6	2.2	1.5
Kapuskasing	(0.2)	9.9	(0.3)	12.9
Mamquam	3.3	1.9	4.6	2.3
Nipigon	(1.3)	1.5	0.9	2.0
North Bay	(0.1)	9.8	0.1	13.4
Williams Lake	-	1.2	5.1	3.7
Other	(1.5)	6.3	(4.1)	6.4
Total	**1.2**	**31.1**	**8.5**	**42.3**
Totals				
Consolidated projects	2.9	43.2	16.6	58.5
Equity method projects	10.4	(54.6)	22.8	(47.0)
Un-allocated corporate	0.3	(0.6)	2.4	1.7
Total Project Income	**$13.6**	**($12.1)**	**$41.8**	**$13.2**

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates. (2) Project sold in November 2017

Project Adjusted EBITDA by Project, Q2 and YTD June 2018 vs Q2 and YTD June 2017

($ millions)

	Three months ended June 30		Six months ended June 30	
	2018	2017	2018	2017
East U.S.				
Cadillac	$2.7	$2.7	$4.7	$4.5
Curtis Palmer	9.6	13.1	20.8	24.0
Kenilworth	0.3	(0.1)	1.3	0.7
Morris	3.9	2.1	8.2	2.9
Piedmont	2.6	2.4	3.9	3.5
Chambers (1)	4.3	3.3	10.1	8.7
Orlando (1)	7.8	5.8	15.3	12.9
Selkirk (1) (2)	-	(0.3)	-	(1.0)
Total	**31.2**	**29.1**	**64.4**	**56.2**
West U.S.				
Manchief	(3.8)	3.3	(0.2)	6.7
Naval Station	(0.4)	2.7	(0.2)	4.0
Naval Training Center	(0.4)	1.7	(0.5)	2.1
North Island	(0.4)	2.1	(0.1)	3.5
Oxnard	0.9	0.5	(0.6)	(0.3)
Frederickson (1)	2.8	(0.2)	6.3	3.1
Koma Kulshan (1)	0.6	0.6	0.8	0.7
Total	**(0.7)**	**10.6**	**5.4**	**19.8**
Canada				
Calstock	1.5	1.1	3.3	2.6
Kapuskasing	(0.2)	14.2	(0.3)	21.7
Mamquam	3.9	2.3	5.6	3.1
Moresby Lake	0.1	(0.0)	0.4	0.2
Nipigon	4.8	4.2	12.2	9.9
North Bay	(0.1)	13.5	(0.1)	20.8
Tunis	(1.4)	6.7	(4.1)	6.6
Williams Lake	0.5	3.3	6.1	7.9
Total	**9.0**	**45.2**	**23.2**	**72.8**
Totals				
Consolidated projects	23.9	75.8	60.5	124.2
Equity method projects	15.6	9.2	32.4	24.5
Un-allocated corporate	0.3	0.4	0.2	0.5
Total Project Adjusted EBITDA	**$39.8**	**$85.4**	**$93.2**	**$149.3**

	Three months ended June 30		Six months ended June 30	
	2018	2017	2018	2017
Total Project Adjusted EBITDA	**$39.8**	**$85.4**	**$93.2**	**$149.3**
Interest expense, net	$0.9	$2.5	1.9	5.3
Depreciation and amortization	25.1	34.7	53.1	69.3
Change in fair value of derivative instruments	0.2	2.6	(3.6)	3.8
Impairment	-	57.7	-	57.7
Project income (loss)	**$13.6**	**($12.1)**	**$41.8**	**$13.2**
Other income, net	(0.2)	0.0	(2.2)	-
Foreign exchange (gain) loss	(5.4)	5.9	(13.6)	8.3
Interest expense, net	11.1	18.4	26.1	35.7
Administration	6.2	5.7	12.2	12.1
Income (loss) from operations before income taxes	1.9	(42.1)	19.3	(42.9)
Income tax expense (benefit)	0.9	(22.3)	4.2	(22.6)
Net income (loss)	**$1.0**	**($19.8)**	**$15.1**	**($20.3)**
Net income attributable to preferred share dividends of a subsidiary company	1.6	2.1	(0.1)	4.3
Net (loss) income attributable to Atlantic Power Corporation	**($0.6)**	**($21.9)**	**$15.2**	**($24.6)**

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates. (2) Project sold in November 2017

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	YTD 2018
East U.S.								
Cadillac	$0.3	$1.3	$1.0	$1.0	$3.5	$0.3	$1.3	$1.5
Curtis Palmer	9.9	13.5	8.5	7.5	39.3	9.5	13.0	22.5
Kenilworth	0.7	0.7	0.2	0.7	2.3	1.4	0.5	1.8
Morris	0.5	0.3	(1.2)	5.6	5.1	6.9	3.4	10.4
Piedmont	0.0	0.0	0.0	2.3	2.3	1.3	1.3	2.5
Chambers (1)	3.4	0.0	3.2	0.0	6.6	0.0	5.9	5.9
Orlando (1)	1.6	7.2	9.6	9.4	27.8	2.6	9.7	12.2
Selkirk (1)(2)	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**	**56.8**
West U.S.								
Manchief	1.9	1.0	4.2	2.8	9.9	3.2	0.6	3.8
Naval Station	1.5	1.7	4.0	1.7	8.8	1.2	(0.7)	0.4
Naval Training Center	0.8	0.7	2.2	1.1	4.8	0.8	(0.5)	0.4
North Island	1.4	1.3	3.4	2.0	8.1	1.4	(0.7)	0.8
Oxnard	(0.3)	(1.4)	(2.0)	7.6	3.9	(0.2)	(0.2)	(0.4)
Frederickson (1)	1.9	3.2	2.4	3.1	10.5	4.0	3.0	7.0
Koma Kulshan (1)	0.3	0.0	0.5	0.0	0.8	0.6	0.1	0.7
Total	**7.6**	**6.4**	**14.5**	**18.3**	**46.8**	**11.0**	**1.8**	**12.7**
Canada								
Calstock	0.7	1.6	0.0	1.7	3.9	2.9	1.8	4.7
Kapuskasing	6.7	14.9	6.0	4.7	32.4	6.3	(0.2)	6.0
Mamquam	0.5	1.5	2.3	0.9	5.2	1.9	2.7	4.6
Moresby Lake	0.3	(0.3)	0.1	0.3	0.4	0.6	(0.1)	0.5
Nipigon	5.5	4.8	4.3	2.9	17.5	10.0	5.7	15.7
North Bay	7.1	14.5	5.3	4.0	30.8	6.6	(0.1)	6.5
Tunis	(0.7)	6.6	(0.2)	(1.6)	4.2	(0.5)	(3.1)	(3.6)
Williams Lake	2.4	2.1	6.5	3.8	14.8	4.0	1.2	5.2
Total	**22.4**	**45.7**	**24.3**	**16.7**	**109.1**	**31.7**	**8.0**	**39.7**
Total Cash Distributions	**$46.2**	**$75.0**	**$60.2**	**$61.4**	**$242.8**	**$64.5**	**$44.7**	**$109.2**
Consolidated	39.0	64.7	44.5	48.9	197.1	57.4	26.0	83.3
Equity Method	7.2	10.3	15.7	12.5	45.7	7.1	18.8	25.8

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates. (2) Project sold in November 2017

AtlanticPower Corporation

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 [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 June 30,		Six months ended June 30,	
	2018	**2017**	**2018**	**2017**
Net (loss) income attributable to Atlantic Power Corporation	**($0.6)**	**($21.9)**	**$15.2**	**($24.6)**
Net income (loss) attributable to preferred share dividends of a subsidiary company	1.6	2.1	(0.1)	4.3
Net income (loss)	**$1.0**	**($19.8)**	**$15.1**	**($20.3)**
Income tax expense (benefit)	0.9	(22.3)	4.2	(22.6)
Income (loss) from operations before income taxes	1.9	(42.1)	19.3	(42.9)
Administration	6.2	5.7	12.2	12.1
Interest expense, net	11.1	18.4	26.1	35.7
Foreign exchange (gain) loss	(5.4)	5.9	(13.6)	8.3
Other income, net	(0.2)	-	(2.2)	-
Project income (loss)	**$13.6**	**($12.1)**	**$41.8**	**$13.2**
Reconciliation to Project Adjusted EBITDA				
Depreciation and amortization	$25.1	$34.7	$53.1	$69.3
Interest expense, net	0.9	2.5	1.9	5.3
Change in the fair value of derivative instruments	0.2	2.6	(3.6)	3.8
Impairment	-	57.7	-	57.7
Project Adjusted EBITDA	**$39.8**	**$85.4**	**$93.2**	**$149.3**

Reconciliation of Net Income (Loss) to Project Adjusted EBITDA by Segment, Q2 2018 vs Q2 2017

($ millions)

Three months ended June 30, 2018

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net income (loss) attributable to Atlantic Power Corporation	$18.4	($6.3)	$1.2	($13.9)	($0.6)
Net income attributable to preferred share dividends of a subsidiary company	-	-	-	1.6	1.6
Net income (loss)	18.4	(6.3)	1.2	(12.3)	1.0
Income tax expense	-	-	-	0.9	0.9
Income (loss) before income taxes	18.4	(6.3)	1.2	(11.4)	1.9
Administration	-	-	-	6.2	6.2
Interest expense, net	-	-	-	11.1	11.1
Foreign exchange gain	-	-	-	(5.4)	(5.4)
Other income, net	-	-	-	(0.2)	(0.2)
Project Income (loss)	18.4	(6.3)	1.2	0.3	13.6
Change in fair value of derivative instruments	0.5	-	(0.2)	(0.1)	0.2
Depreciation and amortization	11.4	5.6	8.0	0.1	25.1
Interest, net	0.9	-	-	-	0.9
Project Adjusted EBITDA	$31.2	($0.7)	$9.0	$0.3	$39.8

Three months ended June 30, 2017

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net (loss) income attributable to Atlantic Power Corporation	($43.3)	$0.7	$31.1	($10.4)	($21.9)
Net income attributable to preferred share dividends of a subsidiary company	-	-	-	2.1	2.1
Net income (loss)	(43.3)	0.7	31.1	(8.3)	(19.8)
Income tax benefit	-	-	-	(22.3)	(22.3)
Income (loss) before income taxes	(43.3)	0.7	31.1	(30.6)	(42.1)
Administration	-	-	-	5.7	5.7
Interest expense, net	-	-	-	18.4	18.4
Foreign exchange loss	-	-	-	5.9	5.9
Project (loss) income	(43.3)	0.7	31.1	(0.6)	(12.1)
Change in fair value of derivative instruments	0.7	-	0.9	1.0	2.6
Depreciation and amortization	11.4	10.0	13.2	0.1	34.7
Interest, net	2.6	(0.1)	-	-	2.5
Impairment	57.7	-	-	-	57.7
Project Adjusted EBITDA	$29.1	$10.6	$45.2	$0.5	$85.4

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

($ millions)

Six months ended June 30, 2018

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net income (loss) attributable to Atlantic Power Corporation	$39.1	($8.2)	$8.5	($24.2)	$15.2
Net loss attributable to preferred share dividends of a subsidiary company	-	-	-	(0.1)	(0.1)
Net income (loss)	39.1	(8.2)	8.5	(24.3)	15.1
Income tax benefit	-	-	-	4.2	4.2
Income (loss) from operations before income taxes	39.1	(8.2)	8.5	(20.1)	19.3
Administration	-	-	-	12.2	12.2
Interest expense, net	-	-	-	26.1	26.1
Foreign exchange gain	-	-	-	(13.6)	(13.6)
Other income, net	-	-	-	(2.2)	(2.2)
Project income (loss)	39.1	(8.2)	8.5	2.4	41.8
Change in fair value of derivative instruments	0.2	-	(1.4)	(2.4)	(3.6)
Depreciation and amortization	23.2	13.6	16.1	0.2	53.1
Interest, net	1.9	-	-	-	1.9
Project Adjusted EBITDA	$64.4	$5.4	$23.2	$0.2	$93.2

Six months ended June 30, 2017

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net (loss) income attributable to Atlantic Power Corporation	($30.8)	$-	$42.3	($36.1)	($24.6)
Net income attributable to preferred share dividends of a subsidiary company	-	-	-	4.3	4.3
Net (loss) income	(30.8)	-	42.3	(31.8)	(20.3)
Income tax benefit	-	-	-	(22.6)	(22.6)
(Loss) income from operations before income taxes	(30.8)	-	42.3	(54.4)	(42.9)
Administration	-	-	-	12.1	12.1
Interest expense, net	-	-	-	35.7	35.7
Foreign exchange loss	-	-	-	8.3	8.3
Project (loss) income	(30.8)	-	42.3	1.7	13.2
Change in fair value of derivative instruments	1.3	-	4.1	(1.6)	3.8
Depreciation and amortization	22.7	19.8	26.4	0.4	69.3
Interest, net	5.3	-	-	-	5.3
Impairment	57.7	-	-	-	57.7
Project Adjusted EBITDA	$56.2	$19.8	$72.8	$0.5	$149.3