UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

FORM 8-K

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

Date of report (Date of earliest event reported): **August 3, 2018**

ATLANTIC POWER CORPORATION

(Exact Name of Registrant as Specified in Charter)

British Columbia	**001-34691**	**55-0886410**
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

3 Allied Drive, Suite 220 **Dedham, MA**	**02026**
(Address of Principal Executive Offices)	(Zip Code)

Registrant's Telephone Number, Including Area Code **(617) 977-2400**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

☐ Written communication pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communication pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communication pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (17 CFR §230.405) or Rule 12b-2 of the Securities Exchange Act of 1934 (17 CFR §240.12b-2).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 2.02. Results of Operations and Financial Condition.

On August 3, 2018, Atlantic Power Corporation (the "Company") held its second quarter 2018 financial results conference call and webcast. A copy of management's prepared remarks and a copy of the related presentation are attached hereto as Exhibits 99.1 and 99.2, respectively, and are hereby incorporated by reference.

The information in Item 2.02, including Exhibits 99.1 and 99.2 is being furnished and shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 (the "Exchange Act") or otherwise subject to the liability of that Section, nor shall such information be deemed to be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933 or the Exchange Act, except as otherwise stated in that filing.

Item 9.01. Financial Statements and Exhibits

(d) *Exhibits*

Exhibit Number	Description
99.1	Atlantic Power Corporation's management's prepared remarks with respect to the Atlantic Power Corporation second quarter 2018 financial results conference call and webcast.
99.2	Presentation prepared with respect to the Atlantic Power Corporation second quarter 2018 financial results conference call and webcast.

SIGNATURES

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

Atlantic Power Corporation

Dated: August 3, 2018	By:	/s/ TERRENCE RONAN
		Name: Terrence Ronan
		Title: *Chief Financial Officer*

Exhibit 99.1

PREPARED REMARKS
Q2 2018
AUGUST 3, 2018

Ron Bialobrzeski — Atlantic Power Corporation — Director, Finance

Page 2: Cautionary Note Regarding Forward-Looking Statements

Financial figures that are presented in this document and the presentation are stated in U.S. dollars and are approximate unless otherwise noted.

Management's prepared remarks presented in this document include forward-looking statements. As discussed on page 2 of the accompanying presentation, these statements are not guarantees of future performance and involve certain risks and uncertainties that are more fully described in our various securities filings. Actual results may differ materially from such forward-looking statements. Please see Atlantic Power Corporation's Safe Harbor statement, presented on page 2 of the accompanying presentation, which can be found in the Investor Relations section of our website.

In addition, the financial results in the Company's press release and the presentation include both GAAP and non-GAAP measures, including Project Adjusted EBITDA. For reconciliations of this measure to the most directly comparable GAAP financial measure to the extent that they are available without unreasonable effort, please refer to the press release, the Appendix of the presentation or our quarterly report on Form 10-Q, all of which are available on our website.

For additional information, please refer to our most recent SEC filings, which can be accessed free of charge on our website, www.atlanticpower.com, an d on EDGAR and SEDAR.

James J. Moore, Jr. — Atlantic Power Corporation — President & CEO

My remarks will include a summary of our second quarter 2018 financial results as well as recent operational and commercial developments. I will also revisit a couple of areas that I addressed in my letter to shareholders three months ago.

Page 4: Q2 2018 Highlights

As noted on page 4 of the presentation, second quarter results were modestly better than we had anticipated, as occurred in the first quarter as well. Although results for the first half reflect a significant decline from Power Purchase Agreement (PPA) expirations and the non-recurrence of the 2017 OEFC Settlement, as we expected, they are on track with our full year 2018 guidance.

During the second quarter we continued to use our strong operating cash flow to repay debt. We remain on track to repay a total of $100 million of debt this year. Our leverage ratio, which has been on a generally declining trend since 2013, increased this quarter to 3.8 times because of the significant decline in EBITDA that we are experiencing this year as a result of several PPA expirations and the non-recurrence of the OEFC Settlement. However, we expect our leverage ratio to begin declining again in 2019 as we continue to repay significant amounts of debt.

We've taken a balanced approach to capital allocation. From April through the end of July, we used $4.6 million of our discretionary cash to repurchase and cancel common and preferred shares. We will continue to do so when they are trading at attractive implied returns, as is currently the case. Although we often highlight the total amount of debt we have repaid (approximately $1.1 billion since 2013), I would note that we also have repurchased a total of $29.5 million in common shares since the spring of 2015 (and insiders have purchased another $4.9 million during this period).

In early July, we announced the acquisition of our partners' interests in the Koma Kulshan hydro facility for a total of $13.2 million, approximately 11 times estimated pro forma cash distributions. This is our first external growth investment following our three-year program to improve performance and strengthen our balance sheet. We closed this acquisition last Friday (July 27). Koma is our longest-dated PPA, with close to a 19-year remaining life.

At June 30, 2018, we had strong liquidity of $203 million, including approximately $42 million of discretionary cash. Although most of our operating cash flow is allocated to debt repayment, we intend to continue using our liquidity for share repurchases and additional growth investments, when they are accretive to intrinsic value per share.

In the area of operations, our Manchief plant completed its major gas turbine overhaul largely as expected. We completed the commissioning of our Tunis plant, though re-start has been delayed to October pending review by the Ontario Independent Electricity System Operator of the commissioning report. At Williams Lake, we've taken steps to reduce operation and maintenance costs to mitigate the impact of higher fuel costs. We are still awaiting regulatory approval (from the BCUC) of the short-term contract extension.

On the commercial front, we remain engaged with the Navy regarding site control for the Naval Station and North Island projects but continue to regard the probability of success as low. We are proceeding with plans to decommission all three sites, but have not yet finalized the cost or timing pending resolution with the Navy.

<u>Page 5: Mitigating the Financial Impact of PPA Expirations</u>

Turning to page 5, I'd like to discuss briefly how we think about the financial impact of PPA expirations over the next several years.

As I noted in my letter to shareholders earlier this year, if power prices remain at current levels (or decline further), the price we receive for power post-PPA would be materially below current contract levels. Some of our projects would not be re-contracted and we would consider mothballing or decommissioning them. The market is very focused on the EBITDA impact of these expirations. So are we, but there are mitigating elements when one considers the overall financial impact on Atlantic Power:

First, the timing of PPA expirations is lumpy . From year-end 2017 through April 1 of this year — a three-month period — six PPAs expired. The reduction to our 2018 results (relative to 2017) was about $83 million. In addition, 2018 results were reduced $29 million by the non-recurrence of the OEFC Settlement recorded in 2017. But between now and April 2022, we have only four PPAs scheduled to expire, which together generate annual EBITDA of approximately $15 million.

Second, we will achieve significant delevering during this period . Our existing projects generate significant cash flow that is in excess of their needs for maintenance, capex, interest and principal payments (on project debt), and working capital. The majority of that excess cash flow is distributed to the parent, and we use it to pay down the term loan. Over the next four years, we expect to reduce total debt by more than half, to slightly less than $400 million. This will result in significantly lower cash interest payments, which means that our operating cash flow will be reduced less than our EBITDA, and our leverage ratio will decline because debt repayment during this period has a more meaningful impact on the ratio than the decline in EBITDA from PPA expirations.

Third, our refinancing risk is minimal . During this period we have only one bullet maturity — the $19 million (US$ equivalent) remaining on our Series D convertible debentures, in December 2019.

Fourth, as we've discussed in the past, we've reduced our corporate overhead costs by approximately 60% in the past five years. We continue to identify additional cost savings, though these are modest.

Certainly there is additional risk from PPAs expiring in 2022 and beyond. But even then, we expect to generate sufficient cash flow to continue reducing debt. By about 2025, we would expect to be approximately net debt-free.

<u>Slide 6: Commercial Successes</u>

Although my discussion has focused on the financial implications of not being successful in re-contracting PPAs over the medium term, I would emphasize that our Commercial team has had a number of successes over the past several years, as noted on page 6 of the presentation. These include:

- In **Ontario** , we agreed to revisions to our contracts that achieved benefits for us as well as the customer, negotiated a settlement with the OEFC that produced significant cash flow for us (about $29 million US$ equivalent), and negotiated a revised contractual arrangement for Nipigon (through 2022) that we believe will be beneficial. In addition, we obtained a new long-term PPA for Tunis (to 2033) in a very difficult power market, and expect to return the plant to service this October.

- In **San Diego** , we obtained new seven-year contracts for Naval Station and North Island that would have produced strong returns on the incremental required investment, though the projects are unlikely to return to service due to our inability to achieve site control with the Navy. Importantly, we were able to terminate the original PPAs ahead of schedule without incurring any financial penalties.

- We agreed on a short-term extension of the PPA for **Williams Lake** . Although the economics of the extension are marginal, the extension can serve as a bridge to a potential longer-term PPA. The extension is still subject to regulatory approval.

- We executed an 11-year extension at **Morris** to 2034 on terms comparable to the existing PPA.

- We achieved an operational turnaround at **Piedmont** and paid off the project's debt, leaving a debt-free plant that now distributes cash to the parent and has a PPA that runs through 2032.

- We consolidated ownership of **Koma Kulshan** at an attractive valuation and now own 100% of this small hydro plant with a PPA that runs through 2037.

Another topic that I covered in my letter to shareholders was the state of the power markets. In the past few months, there have been a few positive data points, although it's far too early and the examples too limited to call this a trend. Still, it is noteworthy that prices can go up as well as down. Specifically:

The May 2018 capacity auction in **PJM** , which set the capacity price for the June 2021- May 2022 delivery year, cleared at a higher price than expected, mostly because of a lower amount of cleared capacity, reflecting nuclear plant retirements and more modest new gas build than in years past. The price in the ComEd zone, where our Morris plant is located, increased to \$195.55 per MW-day from \$188.12 the previous year. In the non-constrained zones, the price increased to \$140 from \$76.53 the previous year.

In **California** , issues have emerged this summer due to gas pipeline outages and other factors that have reduced gas supply availability, low hydro reservoirs, plant retirements, the increasing penetration of renewables on the grid (which can result in higher volatility), and other factors. As a result, extremely high temperatures in southern California during late July have resulted in much higher spot prices for both gas and power.

In **Alberta** (where we do not have any plants), both spot and forward power prices have responded strongly to plant retirements and PPA terminations that have improved the supply/demand outlook as well as the release of details of the final capacity market design (to be implemented in 2021, with the initial auction expected in late 2019). The combination of lower gas prices in the region and higher power prices has benefited spark spreads (the margins realized by gas plants). Increased volatility has benefited gas peakers and plants such as hydro that provide ancillary services.

One example to the contrary is **ERCOT** (another market where we have no plants), where a heat wave in July resulted in new peak demand records being set. Spot prices reacted, though price spikes were relatively modest and short-lived, and forward prices actually declined.

Dan Rorabaugh — Atlantic Power Corporation — SVP, Asset Management

Page 7: Q2 2018 Operational Performance

Beginning with our safety record, we had one recordable injury in the second quarter of 2018 (following a first quarter in which we had none). We continue to place the highest priority on maintaining a strong culture of safety and regulatory compliance.

Turning to our operating results for the second quarter, generation declined 13.2% overall, driven primarily by declines at our San Diego projects, which we shut down on February 7, and at Curtis Palmer, which experienced significantly lower generation due to lower water flows than the year-ago period. On the positive side, Orlando benefited from a shorter spring maintenance outage this year as compared to 2017; Mamquam had significantly higher water flows than the year-ago period; Manchief experienced higher dispatch, notwithstanding being out for part of the quarter for its gas turbine overhaul; and Kenilworth had a maintenance outage in the 2017 period.

Our availability factor in the second quarter of 2018 increased to 93.4% from 83.6% in the year-ago period. The increase reflects maintenance outages at Frederickson and Kenilworth in 2017; a forced outage at Mamquam in 2017, and a shorter spring outage this year at Orlando, partially offset by reduced availability at Manchief due to the gas turbine overhaul in 2018.

With respect to our hydro plants, generation at Curtis Palmer was approximately 28% below the second quarter of 2017 (which was a very strong water year) and 7% below the long-term average. Water flows at Mamquam have been well above the 2017 level (which was close to an average year) as well as above the long-term average. Generation at Mamquam was up 35% versus the second quarter of 2017 and up 22% compared to the long-term average.

Page 8: Operations Update

We have completed all significant work required to return our Tunis project to service. Capacity and environmental compliance testing is scheduled for later this month. The total cost of the re-start of approximately $5 million (US$ equivalent) was in line with our expectations. This cost, most of which was incurred in the first six months of 2018, was expensed. As we have indicated previously, we expect 2018 Project Adjusted EBITDA for Tunis to be negative due to the re-start expenses (its EBITDA for the first six months of 2018 was US$(4.1) million).

Last quarter we indicated that our planned re-start date for Tunis was July 1st. Subsequent to our conference call, we learned that because we had converted Tunis to operate in dispatchable mode (per the new PPA) and installed a new control system for the project, the Ontario Independent Electricity System Operator (IESO) requires a commissioning report to be filed as part of the registration process. The independent engineer for the project filed the commissioning report with the IESO on July 30. The timeline for IESO review is typically about 60 days. If the IESO does not raise any significant issues with the report that we must address, we should be able to commence operation of the project under the PPA in October.

Once returned to service, Tunis will operate as a simple-cycle plant under a 15-year PPA under which it will receive capacity payments for being available and will bid into the market based on its cost of production. We expect it to generate approximately US$2 million of Project Adjusted EBITDA annually.

As discussed last quarter, we also plan to return Nipigon to service as a simple-cycle plant under the terms of its long-term enhanced dispatch contract (LTEDC), which runs through December 2022. Nipigon will operate as a flexible plant, running only when needed and when it is economic to operate. It will receive monthly capacity-type payments and earn energy revenues for those periods when it operates. The economics of the LTEDC are favorable versus the original PPA.

We do not need to perform any overhauls of Nipigon's major equipment prior to its return to service. We plan to upgrade the plant's gas turbine control system in 2019, which will enable remote simple cycle operation. We do not expect to be required to file a commissioning report with the IESO for Nipigon. Thus, we continue to expect that the project will operate under the LTEDC beginning in November of this year.

In terms of other significant maintenance work this year, we completed the major gas turbine outage at Manchief in late May. The gas turbine overhaul at

Kenilworth is expected to be completed in early September, though the plant continues to operate on a leased engine while the work is being done, selling power and steam to Merck under the PPA and fulfilling its obligations to PJM. Some of the Kenilworth maintenance expense that we had expected to incur in the second quarter has been shifted into the third. During the quarter, we completed routine annual maintenance at Frederickson, Morris and Piedmont. Lastly, the runner replacement at Mamquam that had been planned for late summer has been deferred to the first quarter of 2019 due to third-party engineering availability.

A few other areas of focus for the Operations team:

First, following the acquisition of Koma Kulshan on July 27, we have assumed operation of the project from Covanta. The employees at Koma are now Atlantic Power employees. We expect this transition to be seamless.

Second, in order to mitigate the impact of higher fuel costs and the less favorable PPA terms at Williams Lake, in the second quarter we took steps to reduce operation and maintenance expense at the project. We also have made shorter-term fuel supply arrangements which, although not covering 100% of our expected needs, give us a bit more visibility on cost. We still expect that under the short-term contract extension, Williams Lake will be a marginal contributor to Project Adjusted EBITDA.

Third, as we have discussed on previous quarterly calls, we are proceeding with plans to decommission the three San Diego plant sites. We expect to have more to report on our third quarter call.

Fourth, as part of our ongoing initiative to analyze, identify and achieve potential savings in our operation and maintenance costs, we recently retained a consulting firm to perform external benchmarking of our thermal (non-hydro) plants. We expect an initial report this fall, which will look at not only cost structure but also staffing levels, maintenance intervals and other variables. As a sign of the importance of this effort, we have assigned responsibility for the overall program to one of our vice presidents. He has worked on both the operations and commercial teams and will be solely focused on this critical effort. We will provide updates on our operating cost initiatives on future quarterly calls.

Joseph E. Cofelice — Atlantic Power Corporation — EVP Commercial Development

Page 9: Commercial Update

I'll provide an update on the San Diego projects and Williams Lake. There have not been any developments at Kenilworth since our previous quarterly call, when we announced that the customer (Merck) had exercised its option for a one-year extension of the PPA (to September 2019).

San Diego Projects

As previously reported, our three projects in San Diego have not operated since February 7, 2018, when our land use agreements with the U.S. Navy expired. The PPAs with San Diego Gas & Electric (SDG&E) were terminated effective March 1, 2018. Although we signed new seven-year power contracts with SDG&E for Naval Station and North Island that were approved by the California Public Utilities Commission (CPUC) earlier this year, those contracts are conditioned upon us reaching an agreement with the Navy that would allow us to remain on base in order to operate the projects ("site control").

Since the early part of this year, we have been engaged in discussions with the Navy on potential paths to site control at Naval Station and North Island. To date we have not reached an agreement. In order to continue these discussions with the Navy, in July we amended the two power contracts with SDG&E to provide an extension of the date by which we would have to achieve site control. Those amendments are subject to CPUC approval. We view the probability of reaching an agreement for either site as low, so although discussions with the Navy are ongoing, we are continuing to make preparations to decommission both sites. Decommissioning is required by the land use agreements with the Navy.

Separately, last year we executed a power contract with Southern California Edison (SCE) for our NTC project. However, we have been unsuccessful in re-engaging with the Navy regarding site control for NTC. Also, in July 2018, the CPUC rejected the SCE contract for NTC. Therefore, we intend to proceed with the decommissioning of NTC.

Williams Lake

As disclosed previously, Williams Lake is operating under a short-term extension of the contract with BC Hydro that runs to June 30, 2019, or September 30, 2019 at BC Hydro's option. The amended contract is subject to the approval of the BC Utilities Commission (BCUC). The written hearing process before the BCUC commenced in early April and the schedule was recently extended. Although the timing of a decision by the BCUC has not been determined, it is unlikely to be before September. If the BCUC has not approved the short-term extension by September 17, 2018, either party has the right to terminate the contract. This timeframe may be extended at BC Hydro's option.

Separately, written hearings on the appeal of the amended air permit for Williams Lake, which we received in September 2016, continue before the Environmental Appeal Board. We expect the permit to be upheld when this matter is decided, probably in the fourth quarter of this year.

Other Commercial Initiatives

Our commercial team is broadly focused on maximizing the value of our existing assets and sites, as well as pursuing growth opportunities where economically feasible. Although in the past few years our efforts have been focused primarily on PPA extensions and restructurings, we are also, for example, marketing our currently mothballed North Bay and Kapuskasing plants to potential industrial and commercial customers. We believe that current policy and market trends will increase the demand for fully depreciated flexible and reliable peaking generation. Therefore, we view our mothballed gas plants as having potential future value as peaking plants. That is why we are working to preserve optionality at those sites.

We are also in the process of evaluating all our project sites (e.g., land availability, interconnection capacity, and market conditions) for potential competitive advantages for energy storage applications. Although the probability of success is low in any utility request for new PPA proposals, we will participate on an opportunistic basis when the competitive situation warrants. Although confidentiality provisions prevent disclosing project specifics, we submitted our first energy storage bid in the second quarter.

We continue to pursue potential acquisitions on an opportunistic basis, focusing on risk/return as opposed to specific asset classes. On our previous call, we discussed our external growth focus on out-of-favor assets with PPA terms, such as biomass plants. Although we have nothing to report at this time, we believe this focus is more likely to yield opportunities that meet our risk/return targets.

Although we continue to pursue the development of greenfield combined heat and power (CHP) projects, and believe that market fundamentals (e.g., high industrial rates and low natural gas prices) support the development of new CHP projects, greenfield development is a long process and we have recently shifted development resources to potentially nearer-term and higher-probability biomass and energy storage initiatives.

Terry Ronan — Atlantic Power Corporation — EVP & CFO

Pages 10-11: Q2 2018 Financial Highlights

- Project Adjusted EBITDA of $39.8 million declined $45.6 million from the year-ago level of $85.4 million, primarily because of PPA expirations in 2018 and the OEFC Settlement recorded in 2017. However, results were better than expected, due to stronger results at Morris, Mamquam and Kenilworth, partially offset by below-average water flows at Curtis Palmer. Relative to our plan, we also benefited from a shift in the timing of maintenance expense at several projects from the first half of the year to the second. As we catch up with these planned maintenance expenses, and despite the three-month delay at Tunis relative to our previous July 1st assumption, our full year results are projected to remain within our guidance range of $170 to $185 million.

- Cash provided by operating activities decreased $23.5 million to $28.1 million from $51.6 million. Although the decline in Project Adjusted EBITDA had a negative impact on cash flow, the effects were partially offset by lower cash interest payments and favorable changes in working capital, mostly related to PPA expirations and plant shutdowns. Our 2018 estimate of cash provided by operating activities of $95 to $110 million assumes the impact of changes in working capital is nil, but it is more likely to be a positive for the full year.

- During the second quarter we repaid $26.4 million of term loan and project debt. The decline in Project Adjusted EBITDA resulted in an increase in our leverage ratio to 3.8 times. We ended the quarter with liquidity of $203.4 million, including approximately $42 million of discretionary cash.

- We continue to manage our interest rate exposure. At June 30, 2018, approximately 96% of our debt carried either a fixed rate or a variable rate which has been fixed through interest rate swaps. Our exposure to a 100 bp change in LIBOR is approximately $300 thousand over the remainder of 2018 and approximately $450 thousand in 2019.

- Lastly, in the second quarter, we repurchased and canceled approximately 1.3 million common shares at an average price of $2.14 per share and 40,000 shares of our preferred Series 3, at a total cost of $3.4 million. In July, we repurchased and canceled 0.3 million common shares at an average price of $2.14 per share, 5,000 shares of our preferred Series 2 and 41,965 shares of our preferred Series 3, at a total cost of $1.2 million. These repurchases were done under our normal course issuer bid (NCIB). We used a portion of our discretionary cash to fund these purchases.

Page 12: Q2 2018 Project Adjusted EBITDA bridge

Second quarter 2018 Project Adjusted EBITDA results of $39.8 million decreased $45.6 million from $85.4 million in the second quarter of 2017. The decline was expected and primarily attributable to the expirations of six PPAs since December (Kapuskasing, North Bay, Naval Station, North Island, NTC and Williams Lake) and the non-recurrence of the OEFC Settlement (most of which was recorded in the second quarter of 2017). The most significant factors affecting the results were:

PPA expirations. The Kapuskasing and North Bay contracts expired on December 31, 2017 and were not renewed, as expected. Also, both projects received OEFC Settlement revenues in 2017 that did not recur. Together these accounted for $28.1 million of the decline in Project Adjusted EBITDA from the second quarter of 2017. Our three projects in San Diego ceased operations in early February and the PPAs were terminated effective March 1st, which resulted in a $7.7 million reduction in Project Adjusted EBITDA from the second quarter of 2017. The Williams Lake PPA, which was scheduled to expire on April 1, was amended and extended for a short period on less favorable terms; this resulted in a $2.8 million reduction to Project Adjusted EBITDA.

Tunis. Maintenance costs associated with the re-start of Tunis, which are being expensed, and the non-recurrence of OEFC Settlement revenue recorded in the second quarter of 2017 resulted in an $8.1 million reduction in Project Adjusted EBITDA relative to the year-ago quarter.

Manchief . Maintenance expenses of $7.4 million associated with the overhaul of the gas turbine during the quarter resulted in a decline in Project Adjusted EBITDA of $7.2 million from the year-ago period.

Curtis Palmer . Water flows that were well below year-ago levels resulted in reduced generation for Curtis Palmer and a $3.5 million reduction to Project Adjusted EBITDA from the year-ago level.

On the positive side:

Frederickson benefited from lower maintenance expense than in the 2017 period, when it had a major maintenance outage; Project Adjusted EBITDA was $3.0 million higher than the year-ago period.

Orlando benefited from improved availability due to a shorter maintenance outage than in the year-ago period, and to higher contractual capacity rates; Project Adjusted EBITDA increased $2.0 million.

Morris had a $1.7 million increase in Project Adjusted EBITDA, which resulted from a higher capacity price in PJM this year.

Mamquam had a $1.6 million increase in Project Adjusted EBITDA due to higher water flows and lower maintenance expense than the year-ago period.

Page 13: YTD June 2018 Project Adjusted EBITDA bridge

Project Adjusted EBITDA for the six months ended June 2018 of $93.2 million decreased $56.1 million from $149.3 million for the six months ended June 2017. The decline was expected and driven by many of the same factors affecting the second quarter 2018 comparison, primarily PPA expirations, the non-recurrence of the OEFC Settlement, Tunis re-start expenses, the Manchief gas turbine overhaul, and lower water flows at Curtis Palmer. Projects that contributed positively to the comparison included Morris, Frederickson, Orlando and Mamquam, mostly for the same reasons as in the second quarter, and Nipigon, which benefited from a contractual rate increase.

<u>Page 14: Cash Flow Results and Uses of Cash</u>

<u>Second Quarter 2018</u>

Cash provided by operating activities totaled $28.1 million in the second quarter, a decrease of $23.5 million from $51.6 million in the second quarter of 2017. Although the $45.6 million decline in Project Adjusted EBITDA had a negative impact on operating cash flow, this was partially offset by a $13.8 million benefit to cash flow from changes in working capital and an $8.7 million reduction in cash interest payments resulting from debt repayment and a lower spread on our credit facilities. The favorable change in working capital was mostly attributable to a decrease in working capital at projects no longer in operation due to PPA expirations.

During the quarter, we used operating cash flow to repay $20 million of our term loan and to amortize $6.4 million of project debt, including repayment in full of the $5.6 million of debt remaining at Epsilon Power Partners (EPP), ahead of its scheduled amortization later in 2018 and early 2019. We also paid $2.1 million of preferred dividends.

Year-to-date June 2018

Cash provided by operating activities for the six months ended June 2018 of $78.4 million declined $7.3 million from $85.7 million in the comparable 2017 period. Although Project Adjusted EBITDA declined $56.1 million, the reduction in operating cash flow was significantly less due to $34.7 million of favorable changes in working capital, including $17.7 million related to PPA expirations and plant shutdowns (Kapuskasing, North Bay and the three San Diego projects), and a $13.2 million reduction in cash interest payments resulting from debt repayment and a lower spread on our credit facilities.

In the first six months of 2018, we used operating cash flow to repay $50 million of our term loan and to amortize $8.8 million of project debt. We also paid $4.3 million of preferred dividends.

Page 15: Liquidity

At June 30, 2018, we had liquidity of $203.4 million, including $80.8 million of unrestricted cash. These figures were only slightly lower than the March 31st balances of $205.1 million and $82.6 million, respectively. Approximately $49.2 million of the June 30th cash balance was at the parent, which was $10 million higher than the March 31st level. The increase resulted from a release of cash by the projects due to lower working capital needs (at projects no longer in operation). Holding aside approximately $7 million for working capital purposes, we had about $42 million of discretionary cash at June 30.

In the second quarter, we used $3.4 million of discretionary cash for common and preferred share repurchases and another $1.1 million to make an additional equity investment in Koma Kulshan.

As shown on page 15, we do not currently have any borrowings under the revolver, but we do use it for letters of credit. Availability under the revolver was $122.6 million at June 30th, virtually unchanged from the March 31st level.

Although not depicted in this liquidity presentation because it occurred subsequent to quarter-end, I would note that on July 27, we used $12.1 million of discretionary cash to fund the acquisition of Covanta's interest in Koma Kulshan and to buy out the operation and maintenance contract.

Page 16: Debt Repayment Profile

We expect to repay a substantial amount of debt over the next several years, as shown on page 16. Through year-end 2022, we expect to amortize approximately $411 million of our term loan and project debt, predominantly from operating cash flow. During this period, we have only one bullet maturity– the remaining $19 million (US$ equivalent) of the Series D debentures, which mature in December 2019. We can redeem the Series D convertible debentures at par at or before their maturity date, or repurchase a portion of them up to a 10% limit under our NCIB.

With respect to the second half of 2018 specifically, we plan to repay $40 million of our term loan ($20 million in each of the third and fourth quarters) and amortize $1.5 million of project debt (at Cadillac). This would bring debt repayment for the year to a total of $100 million.

Page 17: Projected Debt Balances

Page 17 shows the impact of continued debt repayment on our debt balances, projected through year end 2023. At June 30, 2018, we had debt of $821 million, including our share of debt at Chambers, which is an equity-owned project. Assuming that we amortized the term loan per the targeted debt reduction schedule through year-end 2022 and repaid the remaining $125 million of principal at its maturity in April 2023, our projected debt balance at year-end 2023 of $252 million would consist of the $160 million (US$ equivalent) Medium-Term Notes (with a 2036 maturity), the $87 million (US$ equivalent) Series E convertible debenture (2025 maturity), and $5 million of project debt. However, there are alternative paths we could follow with respect to the final balance on the term loan, including refinancing it prior to its maturity date, extending the maturity date or (as page 17 contemplates), paying off the remaining principal with cash in 2023.

We expect that this substantial debt repayment over the next several years will generate significant interest cost savings that would mitigate the impact of lower Project Adjusted EBITDA (from PPA expirations, or extensions on less favorable terms) on our operating cash flow.

Page 18: 2018 Guidance: Project Adjusted EBITDA bridge vs. 2017 actual

We have 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.

Although the format of the bridge on page 18 is slightly different from previous quarters, there has been no change to our 2018 Project Adjusted EBITDA guidance of $170 to $185 million. As we have noted in the past, approximately $112 million of the decline versus the $288.8 million we reported for 2017 is attributable to PPA expirations, the 2017 OEFC Settlement and Tunis re-start expenses. Although there are other puts and takes, as shown on page 18, they are largely offsetting. As noted earlier, although first half 2018 results were better than our expectations, we expect to give this back in the second half, mostly due to a shift in the timing of maintenance expense and the delay in the Tunis re-start under the new PPA.

Page 19: Bridge of 2018 EBITDA Guidance to Cash provided by operating activities

Based on our 2018 Project Adjusted EBITDA guidance range of $170 to $185 million, we estimate 2018 cash provided by operating activities in the range of $95 to $110 million. This estimate assumes the impact of changes in working capital on cash flow is nil, but given the reduction in working capital attributable to projects no longer in operation (relative to 2017), changes in working capital are more likely to have a positive impact on the 2018 GAAP result.

Our principal planned uses of operating cash flow in 2018 include $90 million amortization of our term loan; $10 million of project debt amortization; $1.4 million of capital expenditures; and $8 million of preferred dividend payments. As previously noted, our repurchases under the NCIB and our acquisition of Koma Kulshan have been funded from our discretionary cash balances.

As previously indicated, our leverage ratio at June 30, 2018 was 3.8 times. Notwithstanding planned debt repayment of $100 million this year, we expect this ratio to increase to the high four times range by year-end 2018, because of the significant expected reduction in 2018 Project Adjusted EBITDA. However, as we continue to repay significant amounts of debt (as shown on page 16), our leverage ratio should begin declining again in 2019. We expect the ratio to move below four times by the end of 2020.

San Diego decommissioning cost estimate

As noted, we are preparing to decommission the three San Diego projects, as required by our land use agreements with the Navy. We have developed a range of cost estimates for each project as well as estimates of expected salvage value. We expect to refine those estimates once the scope of work has been determined together with the Navy. As disclosed previously, we have accrued $1.7 million of decommissioning expense for these projects. If the final cost exceeds our accrual, which is possible, the additional expense would reduce net income, but would not be included in Project Adjusted EBITDA. We expect to provide an update with our third quarter results.

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, 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) on a consolidated basis is provided in Table 1 below.

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Table 1 — Reconciliation of Net income (loss) to Project Adjusted EBITDA
(in millions of U.S. dollars)
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

Exhibit 99.2

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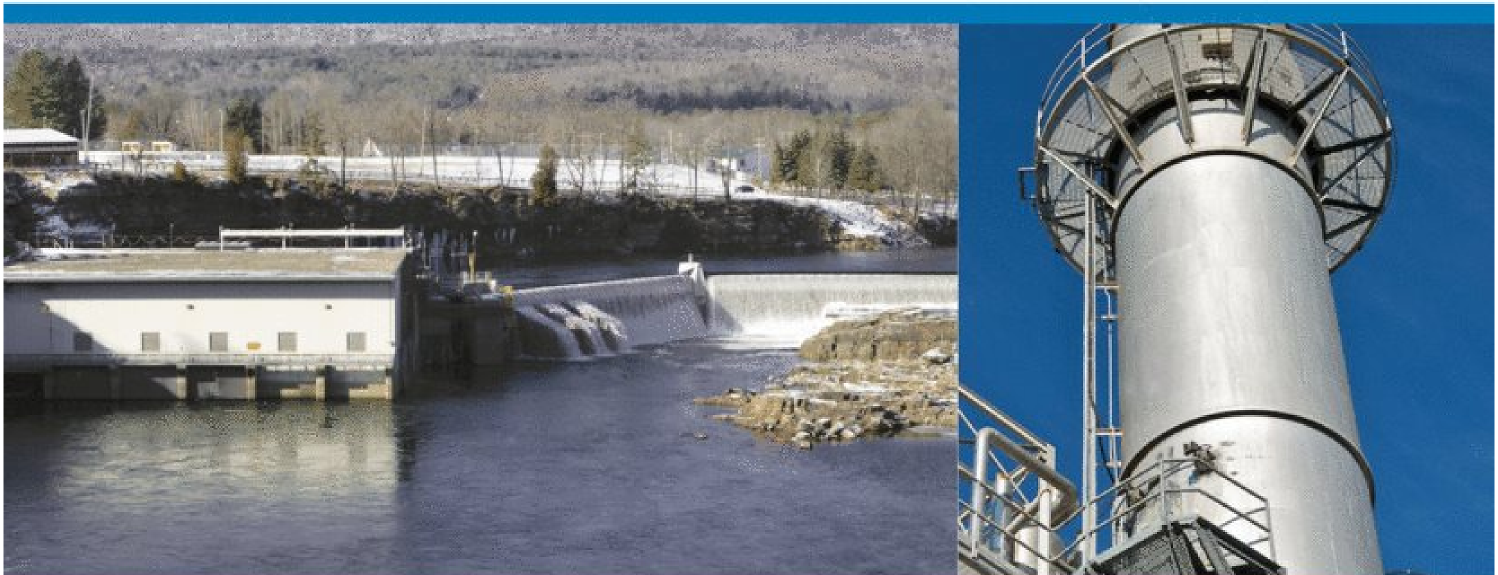

Q2 2018 Financial Results Conference Call

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.

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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

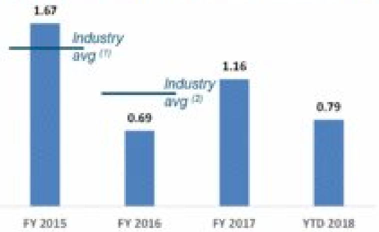
Koma Kulshan

- 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

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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

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Q2 2018 Financial Highlights

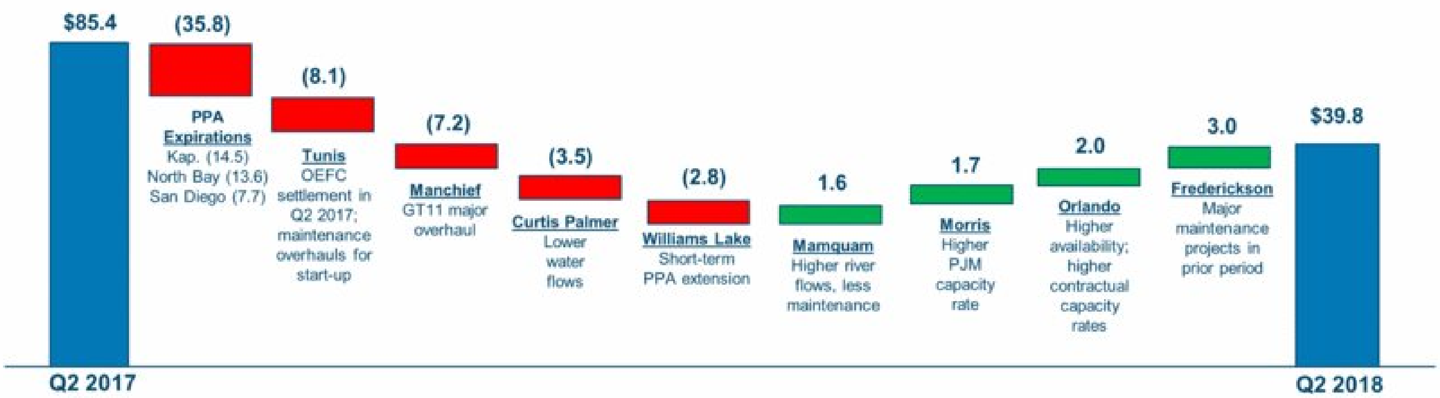
Q2 2018 Financial Results	**Project Adjusted EBITDA** **Q2 2018 $39.8 million vs Q2 2017 $85.4 million** (see bridge on page 12) • Results better than anticipated (Morris, Mamquam, Kenilworth; partially offset by Curtis Palmer) • Some maintenance expense shifted from 1H 2018 to 2H 2018 • On track for 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)

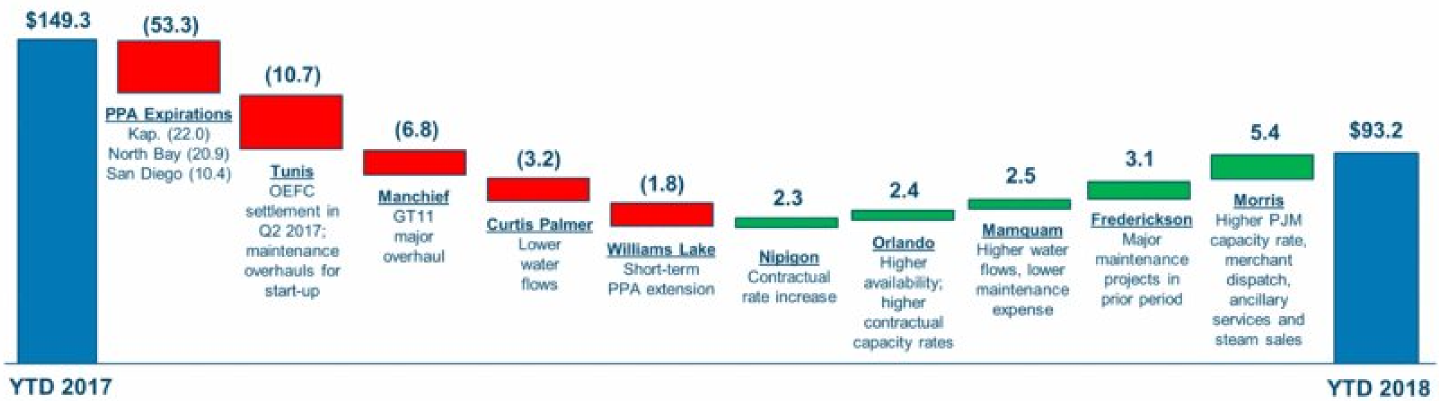
Q2 2018 Project Adjusted EBITDA (bridge vs 2017)

($ millions)



YTD June 2018 Project Adjusted EBITDA (bridge vs 2017)

($ millions)



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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)

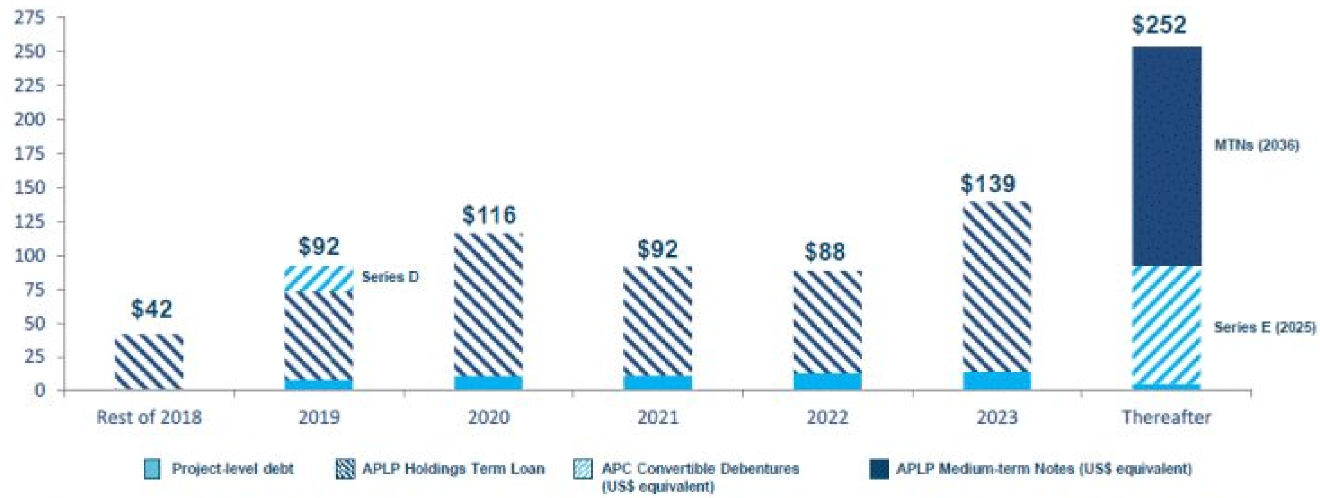
In Q2 2018, we used discretionary cash of $3.4 million for the repurchase of common and preferred shares and $1.1 million for an additional equity investment in the Koma Kulshan hydro project.

(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)

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

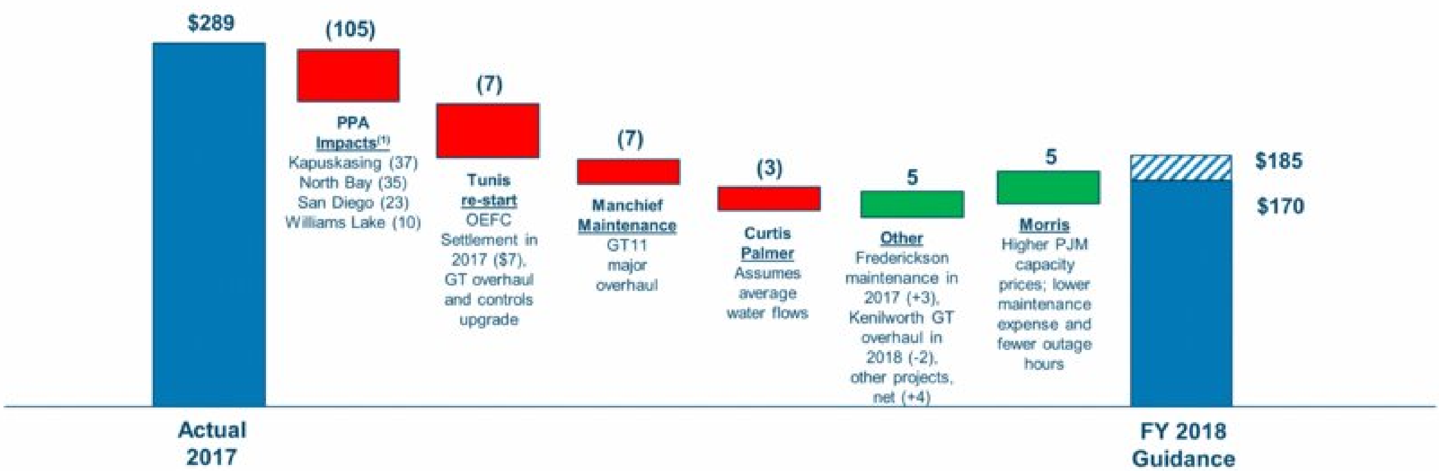
- Term loan – Amortize $365; $125 remaining balance due at maturity in April 2023 [2]
- Project debt (proportional) – Repay $60, ending balance $5
- Series D convertible debentures mature Dec. 2019 ($19 US$ equivalent)

[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

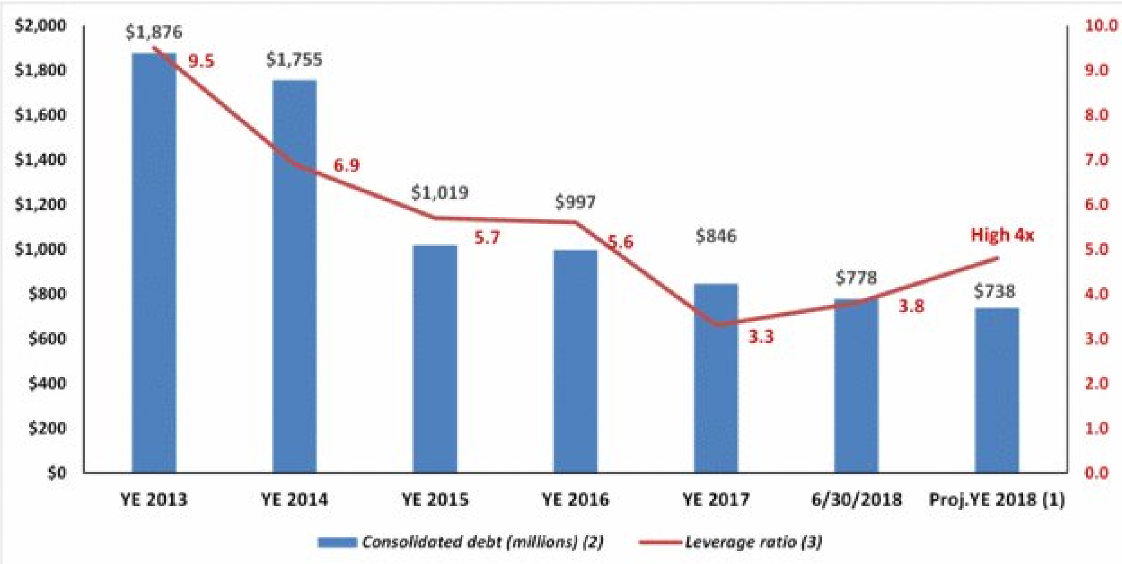
($ millions)

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)



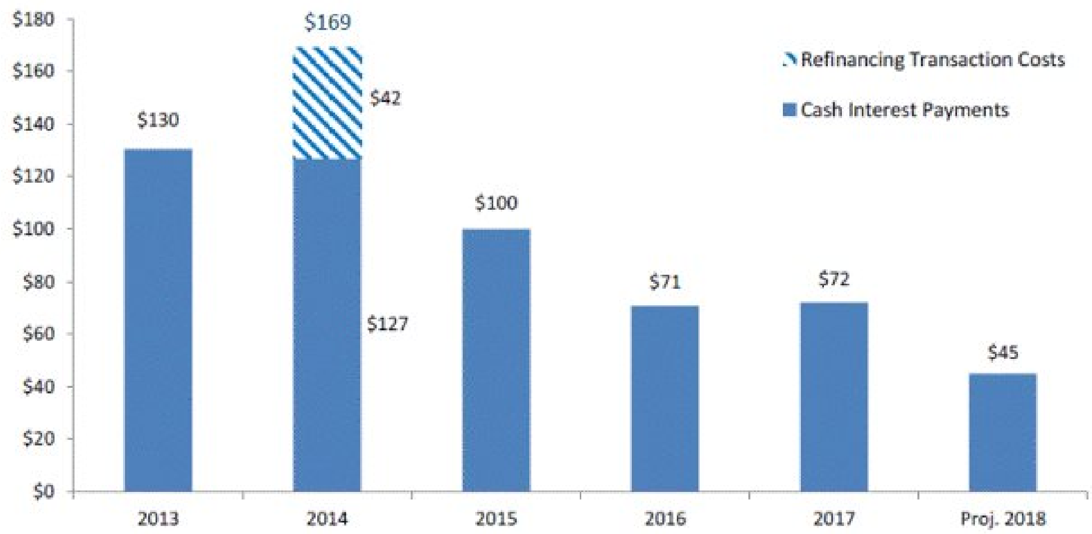
Total net reduction in consolidated debt since YE 2013 of more than <u>$1.1 billion</u>

- **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)

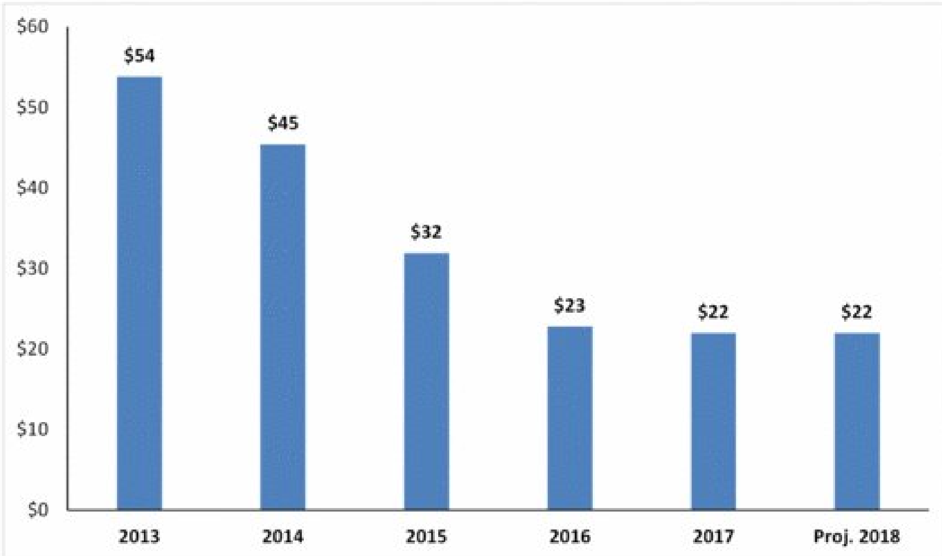


- **Reduction has been driven by debt repayment as well as re-pricings of our term loan and revolver**
- **Re-priced facilities three times, to 300 basis points over LIBOR (had been 500); these re-pricings will save $41 million over the remaining terms of the facilities**

(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.

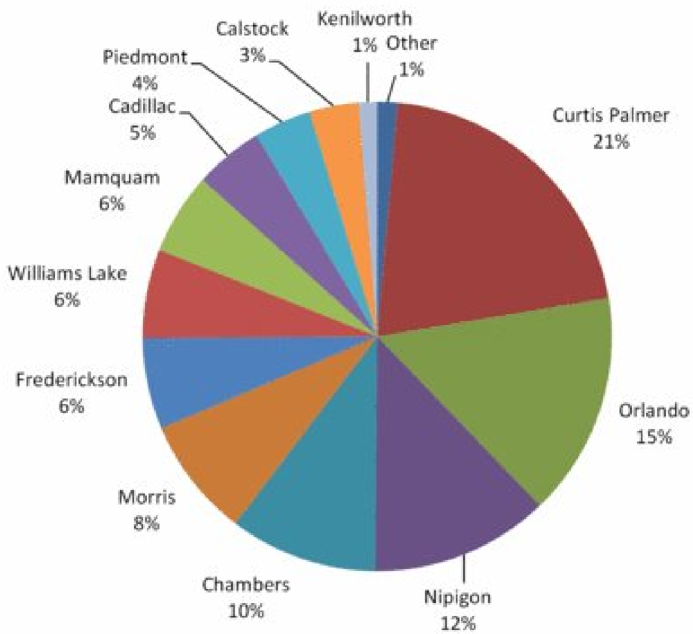
Consolidated cash interest payments include interest payments on the debt included in the Consolidated debt ratio defined above.

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

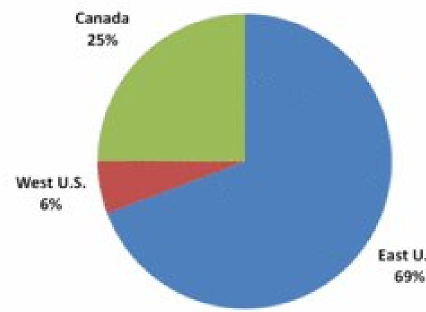
Project Adjusted EBITDA by Project – Six months ended June 30, 2018

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



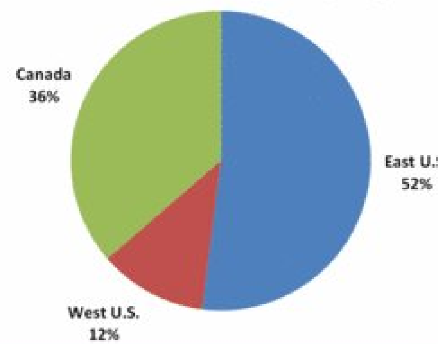
Six months ended June 30, 2018

Project Adjusted EBITDA by Segment (1)



Six months ended June 30, 2018

Cash Distributions from Projects by Segment (2)

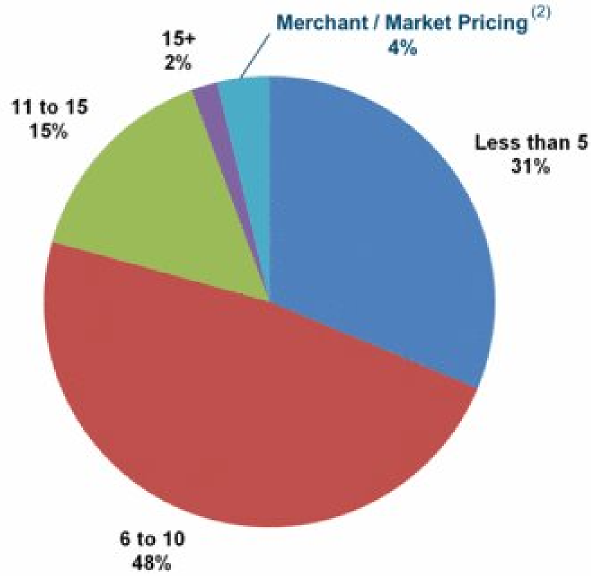


(1) Based on Project Adjusted EBITDA for the six months ended June 30, 2018, excluding non-operational and two other projects that have negative Project Adjusted EBITDA for the period. Un-allocated corporate segment is included in "Other" category for project percentage allocation and allocated equally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

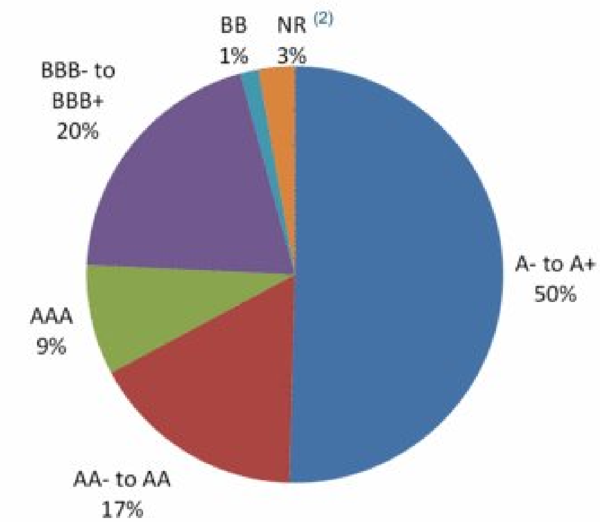
Majority of Cash Flows Covered by Contracts with More Than 5 Years Remaining

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 Pow er 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 pow er 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
- − Frederickson 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 2018	Three months ended June 30 2017	Six months ended June 30 2018	Six months ended June 30 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

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