PREPARED REMARKS
Q1 2017
MAY 5, 2017

Ed Vamenta – Atlantic Power Corporation – Director, FP&A

Slide 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 Slide 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 Slide 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, and on EDGAR and SEDAR.

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

My remarks this quarter will be brief as we did an extensive business review on our fourth quarter and year-end 2016 financial results conference call just two months ago. The text of these remarks can be found on the Investors page of our website under "Presentations."

Other members of the management team will address operational and financial results for the quarter, including an increase to our 2017 guidance, and an update on commercial activities and PPA renewal efforts, although there was not much new on that front. I'd like to focus my remarks on a few key developments since our March conference call:

Slide 5: Recent Developments

Settlement with OEFC re Global Adjustment revenues. In late April, we reached a settlement with the Ontario Electricity Financial Corporation (OEFC) regarding the amount of Global Adjustment revenues that we should have received for our Tunis, Kapuskasing and North Bay plants during the 2013-2017 period. The settlement calls for us to receive additional payments of Cdn$36.1 million, including Cdn$10.7 million received in the first quarter (but deferred for accounting purposes) and another Cdn$20.3 million received earlier this week. The remaining amount will be collected over the balance of the year. In total, this settlement will result in about US$26 million of additional cash flow this year, which will benefit significantly our cash position at the parent.

<u>Slide 6: Recent Developments (cont'd)</u>

Term loan and revolver repricing. In mid-April, we executed a successful repricing of our $615 million term loan and $200 million revolving credit facility. As you may recall, we issued these instruments in April 2016 during challenging market conditions, and pricing was 500 over LIBOR. Since then, we have paid the term loan down to $615 million from the original $700 million size. Market conditions also have improved. On the repricing, we were able to reduce the spread by 75 basis points to LIBOR plus 425 basis points. This will result in $2.4 million of cash interest savings this year and a higher amount next year, with total savings of approximately $17 million over the remaining lives of the facilities, net of $1.3 million of transaction costs.

Piedmont environmental permit. The amendment to Piedmont's Title V air permit issued by the Georgia environmental authorities in April establishes new fuelstock monitoring and recordkeeping requirements, which are not expected to require any significant changes to the way the plant is operated. The amended permit is subject to a public comment period and EPA review before becoming final. We expect that this process will be fully resolved within the next few months.

At that time or shortly thereafter, we expect to be in a position to conclude our evaluation of alternative paths to addressing the August 2018 debt maturity for

Piedmont ($54 million), which include a potential sale process or continued ownership. I'll provide a bit more color on these alternatives:

Given our strengthened balance sheet and reductions in corporate overheads and interest expense, we are under no pressure to sell assets absent compelling terms. We believe that a sale of Piedmont would result in proceeds significantly in excess of the project-level debt and swap breakage costs. Because Piedmont is outside of the term loan structure, the excess proceeds would add to discretionary cash at the parent.

If we were to continue to own the asset, we would consider paying down the debt maturity out of liquidity, either in its entirety or in part in conjunction with a refinancing. The plant is now running well, after an initial period that required some additional investment by us to address operational issues. The PPA, which runs through December 2032, is with a strong counterparty with an A- credit rating. The remaining PPA term of more than 15 years is more than double our portfolio EBITDA-weighted average of approximately 6 years. Although the plant has never made cash distributions, it does generate approximately $8 million of operating cash flow annually, which is currently all being applied to debt service. Reducing or eliminating the debt, which has an average rate of 8.47%, would make this cash flow available for distribution to the parent.

These are good options to be weighing. We will take a patient and disciplined approach in deciding what to do with this asset.

<u>Dan Rorabaugh – Atlantic Power Corporation – SVP, Asset Management</u>

<u>Slide 7: Q1 2017 Operational Performance</u>

We had no recordable injuries in the first quarter, and none in the past seven months. We place the highest priority on maintaining a strong culture of safety and regulatory compliance.

Generation was lower in the first quarter than the year-ago period, primarily due to the fact that we placed Kapuskasing, Nipigon and North Bay into a non-operational state in the first quarter as a result of the revised contractual arrangements for these plants that we announced in January. Accordingly, generation in our Canada segment was substantially lower year-on-year; lower water flows at Mamquam were also a factor in the decreased generation. Availability in the Canada segment (which excludes the non-operational plants) declined primarily due to Mamquam. Generation in the East segment declined approximately 10% primarily because of reduced generation at Morris due to lower merchant demand, while generation in the West segment increased modestly because Naval Station had a major maintenance outage in the year-ago period that did not recur. Availability in our East segment was comparable to the year-ago period and availability in our West segment increased because of the non-recurrence of the Naval Station outage.

With respect to our hydro plants, water flows at Curtis Palmer this quarter were very similar to the first quarter of 2016. Last year, however, conditions deteriorated beginning in the second quarter and continued for most of the year. This year, the snowpack is greater and the lake is full as a result of rain mixed with snowpack. This should bode well for water flows going forward. I'd also mention that we had an increase in frazil ice this past winter, but we were able to use the new spillway bladder that we installed last year to sluice ice and snow and to remove debris. As you may recall, this was one of our optimization projects. It increased our generation by more than 3,000 megawatt-hours. As a result, we have already recouped more than 50% of the installation cost.

Mamquam, which had a record year in 2016 in terms of water flows, was lower this quarter but has recovered some in April with increased precipitation. Snowpack is actually slightly higher than at this time last year.

Slide 8: Operations Update

With respect to Ontario, as we discussed last quarter, we have put our Kapuskasing, North Bay and Nipigon plants into a lay-up mode, or a non-operational status, based on revised contractual arrangements under which we will receive fixed monthly payments without any delivery obligations.

Our current plan is to return our Tunis project, also in Ontario, to service in 2018 under the 15-year PPA that was signed in December 2014. This will require an overhaul of the gas turbine and some maintenance work on other systems, which we expect to undertake in the latter part of 2017. We expect most of the cost, or approximately $7 million, to be incurred and expensed this year. Although this represents our current thinking on timing, scope and cost, we remain in discussions with the relevant parties in Ontario, as discussed in our January 9, 2017 press release, on potential other initiatives that could be beneficial to ratepayers as well as to us. This could affect Tunis or our other Ontario projects.

We have several scheduled maintenance outages this year. Orlando just returned from its major turbine maintenance outage. At Morris, we began work in mid-April on the third and final combustion turbine upgrade, which is part of our optimization program, and expect to complete the upgrade in mid-May. During this period, Morris is continuing to run on the other two gas turbines. We began a major gas and steam turbine outage at Frederickson in late April. We also have a steam turbine overhaul under way at Kenilworth. Overall, though, we expect our maintenance costs in 2017 to be on a par with the 2016 level.

As we discussed last quarter, although we will continue to look for additional optimization projects, this year we have shifted our focus to two other areas where we expect the operations organization to have a leading role – engineering and operations support for PPA-related investments, such as the work at Tunis and possibly at other facilities to the extent that we are successful in extending PPAs elsewhere; and an aggressive initiative to analyze, identify and achieve cost savings. As part of this process we will be benchmarking our operation and maintenance costs as well as our efficiency, and evaluating many of our operational practices such as maintenance intervals and operations parameters with a view toward implementing best practices wherever feasible. We expect to have more to report on this later this year.

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

Slide 9: Commercial Update: PPA Renewal Status

Last quarter we provided an update on how we're approaching near-term PPA expirations in three key markets – Ontario, California and British Columbia. It has been only two months since that conference call, and there is not anything substantive to report. However, I will briefly review where our PPA renewal efforts stand in each of those markets.

In Ontario, as previously mentioned, we reached an agreement with the relevant parties that produces benefits for all sides. As a result of this agreement, we put three of our gas plants into non-operational status. We do not expect either Kapuskasing or North Bay to return to service in the next couple of years, although they may return at a point in time when supply and demand conditions in the province become more favorable.

We continue to have discussions with the relevant parties in Ontario with respect to our plants on other potential initiatives that would produce ratepayer savings while also being beneficial for us. Specifically, this could include a more flexible operating arrangement for Nipigon after October 2018 (when the current enhanced dispatch agreement ends) through the expiration of its PPA in December 2022. We are also open to changes to the Tunis PPA, if they produce benefits for both sides.

In California, as discussed on the previous conference call, we have three plants in San Diego for which the utility customer under the PPAs is San Diego Gas & Electric (SDG&E). All three PPAs expire in December 2019. The plants are located on Navy or Marine Corps bases, and all three sell steam to the Navy or Marines under contracts that expire in February 2018, which is 22 months earlier than the PPA expiration dates. These contracts provide the plants with a right to use the property on which they are located. Neither the Navy nor the Marine

Corps plans to take steam from these plants after the existing agreements end. At that time, unless we are able to make alternate arrangements with the Navy and the Marines, our right to use the property would end and the PPAs with SDG&E could be terminated early, which could result in potential liabilities to us, subject to our ability to mitigate them, as well as a loss of EBITDA.

With this as background, we have been working concurrently with SDG&E (on new PPAs for two of the three plants) and the Navy (to ensure we have site control beyond February 2018). In mid-March, we responded to a solicitation by the Navy for proposals for energy security and resiliency at the bases on which the Naval Station and North Island plants are situated. The process laid out in the solicitation has three phases. Earlier this week, we learned that we have been selected to move to the next phase for both sites. We'll be submitting more detailed proposals by late May. In addition to the PPA discussions we are having with SDG&E, we are continuing to evaluate alternate contractual arrangements for the San Diego plants and Oxnard.

As we disclosed in our previous conference call, to the extent that we are successful in gaining site control and arranging new PPAs for one or more of the San Diego plants, we expect that there would be a substantial reduction in Project Adjusted EBITDA as compared to the current PPAs, given current market conditions. However, we think that even such a reduced level of EBITDA would provide an attractive return on the incremental investment needed to reconfigure and perform major maintenance on the facility. Also, a PPA of intermediate length could serve as a bridge to potentially better power market conditions down the road and preserve the long-term optionality of the plants.

Turning to our Williams Lake biomass plant in British Columbia, we are in discussions with BC Hydro on a potential short-term extension of the PPA, which expires next March. The focus has moved to a short-term extension because of the timing of BC Hydro's Integrated Resource Plan or IRP, which the utility is required to file in November 2018 but which is not expected to be finalized until sometime in 2019. A short-term extension could bridge the plant through the IRP process, which is expected to decide what role biomass will play in the utility's longer-term resource mix. If a short-term extension of the PPA is agreed to, we expect that Project Adjusted EBITDA under the new PPA would be substantially lower than under the existing PPA.

On previous conference calls we have discussed plans for a new fuel shredder at Williams Lake, which would allow the plant to burn a mix of up to 50% rail ties and other alternative fuels. This would allow the plant to remain a low-cost producer of energy and provide environmental disposal benefits to the region.

Last September we received an amended air permit from the Ministry of Environment that would allow us to make these changes in fuel mix by installing a new fuel shredder. Several appeals were filed with the Environmental Appeal Board with respect to the air permit amendment and the corresponding landfill permit amendment. The appeals of the landfill permit amendment have been dismissed. Recent indications are that an oral hearing on the remaining appeals will be held late this year or in the early part of 2018. A decision by the Board could occur in the first half of 2018. We believe that we have a strong position and that ultimately the permit will be upheld.

To be clear, however, the fuel shredder would not be required nor would it be economically feasible under a short-term extension of the PPA. We would proceed with this investment only if we were to reach agreement on a long-term extension of the PPA that provides us the ability to recover our investment in the new shredder and earn a reasonable return.

Terry Ronan – Atlantic Power Corporation – EVP & CFO

Before reviewing first quarter results, I'll address the Global Adjustment settlement with the OEFC that we reached in late April. As previously discussed, we expect to receive total payments of Cdn$36.1 million or approximately US$27 million. Approximately US$20 million of the total relates to Kapuskasing and North Bay and the remaining US$6 to US$7 million is for Tunis and is related to operation of that plant in 2013 and 2014.

We received Cdn$10.7 million or approximately US$8 million of payments in the first quarter of 2017. At the time, we had not reached a settlement with the OEFC, so these amounts were recorded as deferred revenue and included as a current liability on the March 31st balance sheet. Accordingly, they did not benefit operating revenues, Net income or Project Adjusted EBITDA in the first quarter. They were included in Cash provided by operating activities and they are included in cash on the March 31st balance sheet. Having finalized a settlement in the second quarter, all contingent aspects of the gain have been addressed. Thus, we will record these payments as revenues in the second quarter, along with an additional Cdn$20.3 million (or about US$15 million) of payments that we received earlier this week. The remaining Cdn$5.1 million relates to the enhanced dispatch contracts at Kapuskasing and North Bay and will be received and recognized as revenue, when earned, over the balance of this year.

Slide 10: Q1 2017 Project Adjusted EBITDA bridge

We reported $63.8 million of Project Adjusted EBITDA for the first quarter of 2017, an increase of $1.3 million from the $62.5 million reported for the comparable 2016 period. The slight increase was primarily attributable to the impact of the revised operational and contractual arrangements for Kapuskasing and North Bay as well as the expiration of an above-market gas contract for the two plants that expired at year-end 2016. The two plants had a combined increase in Project Adjusted EBITDA for the quarter of $6.8 million. Orlando had a $2.1 million increase in Project Adjusted EBITDA, mostly from the settlement of favorable fuel swaps. Unfavorable comparisons occurred at Morris, which decreased $4.6 million due to several factors, including higher fuel prices, lower fuel optimization, the non-recurrence of a return on a construction project that we received in 2016, and a lower PJM capacity price. Mamquam decreased $1.8 million due to lower water flows and Calstock decreased $1.4 million due to lower waste heat and the expiration of a rate adder under the PPA.

Slide 11: Cash Flow Results and Uses of Cash

Cash provided by operating activities of $34.1 million in the first quarter of 2017 increased $4.7 million from the year-ago figure of $29.4 million. The 2017 result benefited from the approximately $8 million of Global Adjustment deferred revenues (included in cash flow) and a $1.3 million increase in Project Adjusted EBITDA. These favorable variances were partially offset by decreases in cash provided by operating activities from Morris and Mamquam, for reasons previously discussed, and a $2.9 million increase in cash interest payments, which resulted from a higher term loan balance and higher spread on the loan relative to the first quarter of 2016.

During the quarter, we repaid $25 million of our term loan and amortized $2.3 million of project debt. We also made capital expenditures of approximately $2 million and paid preferred dividends of $2.1 million. These uses were funded from our operating cash flow.

Slide 12: Liquidity

At March 31, 2017, we had liquidity of $214 million, including $91.5 million of unrestricted cash. This is approximately $10 million higher than the December 31st level of $204 million, consisting of an approximate $6 million increase in unrestricted cash and a $4 million increase in revolver availability, which resulted from a reduction in letters of credit outstanding. Approximately $66 million of the cash balance is at the parent; holding aside approximately $10 million for working capital purposes, we had about $56 million of discretionary cash at March 31st.

Slide 13: Progress on Debt Reduction and Leverage

Our March 31, 2017 consolidated debt was $971 million. (Note, the debt totals shown on Slide 13 exclude unamortized discounts and deferred financing costs.) During the quarter, we repaid $27 million of term loan and project debt, as previously discussed. Since year end 2013, we have reduced our consolidated debt by more than $900 million as a result of amortization, discretionary repurchases and asset sales. During that same period, our leverage ratio declined from a peak of 9.5 times to 5.4 times at the end of March. Separately, debt at our equity-owned projects has been reduced by more than $90 million during this same period. (Note that our leverage ratio is based on gross debt rather than net, and Adjusted EBITDA, which is after corporate G&A costs.)

Slide 14: Debt Repayment Profile

Our progress to date in debt reduction and the refinancing of our term loan and revolver last year has improved our debt maturity profile considerably. Slide 14 is a schedule of expected debt repayment by year, including amortization, projected repayment of the term loan and bullet maturities. Of note:

- Approximately 57% of our debt is amortizing and the rest is bullet maturities. Compared to the profile of a few years ago, when our corporate debt consisted mostly of bullet maturities, this has reduced the amount of debt subject to refinancing risk.

- We are scheduled to repay another $75 million of our term loan and $9.5 million of project debt in the three remaining quarters of 2017, and expect to repay at least an additional $40 million, for an expected total repayment this year in excess of $150 million.

- Our next bullet maturity at the parent is not until June 2019, when the remaining $42.5 million of Series C convertible debentures mature. The Series D convertible debentures ($60.9 million U.S. dollar equivalent) mature in December of 2019. Both series of convertible debentures are callable at par two years prior to their maturity dates. At the project level, we have a bullet maturity of $54 million at Piedmont in August 2018.

- Although not shown on this slide, our corporate revolver matures in April 2021. We currently do not have any borrowings under the revolver.

Slide 15: Projected Debt Balances

Between now and year-end 2020, we expect to repay approximately $374 million of project and term loan debt, primarily from operating cash flow. This represents approximately 37% of our total debt.

As shown on Slide 15, this projected repayment would reduce our total debt to approximately $640 million at year-end 2020. However, this assumes that we refinance Piedmont in 2018 and either refinance or use our revolver for the 2019 convertible debentures (that is, we are not assuming any reduction in debt for either). However, we expect that we would use some portion of our discretionary cash to address part of these maturities, which should further improve our debt levels during this period.

As previously discussed, we're evaluating different paths to address the Piedmont maturity, including a potential divestiture or a continued ownership where we reduce the debt at Piedmont by using cash, potentially but not necessarily in conjunction with a refinancing. We also have the option of including Piedmont in the term loan structure.

With respect to the convertible debentures, we have not made a decision with respect to addressing these maturities, but the alternatives include repurchases under our normal course issuer bid or NCIB, up to the 10% limit; calling one or both of the issues sometime between their June and December 2017 call dates and their June and December 2019 maturity dates; or a refinancing prior to maturity. We have the option of using up to $100 million under our corporate revolver to address the convertible debentures.

We expect this continued delevering to generate significant interest cost savings that benefit our cash flow. Repaying $374 million of project and term loan debt during this period would result in an additional $20 million of annualized interest cost savings by 2021. If we used cash to redeem all or part of the remaining convertible debentures, that would generate up to another $6 million of annual interest cost savings. By reducing our cash interest payments, we can help to offset a portion of the impact on our cash flow from potential reductions to EBITDA resulting from PPA expirations during this period.

Delevering remains one of our most important financial goals. Although required debt amortization in 2017 is only $112 million, which will be funded from our operating cash flow, we plan to allocate $40 million or more of discretionary cash for additional debt reduction (which could include repurchasing or redeeming convertible debentures, further repayment of the term loan or repayment of the Piedmont project debt). This would bring total debt repayment in 2017 to $150 million or more, and would reduce our year-end 2017 leverage ratio to below 4 times. Although we expect this ratio to increase modestly in 2018 due to lower expected Project Adjusted EBITDA, the magnitude of debt repayment during this period should move the ratio back in the range of 4 times by 2019.

Slide 16: 2017 Guidance: Project Adjusted EBITDA bridge vs. 2016 actual

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.

As disclosed in our May 4, 2017 press release, we have increased our 2017 guidance for Project Adjusted EBITDA to a range of $250 to $265 million from a range of $225 to $240 million. The $25 million increase in guidance is attributable to the Global Adjustment revenues, which we indicated last quarter were not included in our initial 2017 guidance.

We have provided an additional disclosure on this slide in response to questions that we have received. The most important contributor to the higher Project Adjusted EBITDA in 2017 relative to the $202 million recorded in 2016 is the impact of the revised contractual and operational status of our Kapuskasing and North Bay plants in Ontario and the expiration of an above-market contract to supply gas to these plants, all of which occurred at year-end 2016, and the collection of Global Adjustment revenues for these plants under the OEFC settlement.

On Slide 16, we have provided a bridge of the 2016 Project Adjusted EBITDA for these two plants ($10 million) to the estimated 2017 level that is embedded in our guidance (approximately $67 million, including $20 million of Global Adjustment payments), implying an increase of $57 million in 2017. Essentially, this increase accounts for all of the $55 million increase in total Company Project Adjusted EBITDA from $202 million in 2016 to $257.5 million in 2017 (based on the guidance midpoint). Although there are other variables in 2017, as shown in the bridge and discussed below, they are essentially offsetting. Absent the significant increase from these two plants, which is mostly attributable to non-recurring or expiring factors, 2017 results would be more in line with 2016.

As shown on the bridge, the other factors affecting our 2017 guidance are less significant but include:

+ Forecasted return to average water flows, which would result in increased EBITDA from Curtis Palmer, partially offset by a decrease from Mamquam;
+ Full year return on optimization investments, including the final turbine upgrade at Morris to be completed this spring;
+ Lower maintenance expense and higher revenues at Morris, which had an extended scheduled outage in 2016;
− Maintenance expense required to prepare Tunis for a return to service in 2018 under the terms of the PPA, and
− Maintenance expense at Frederickson related to a scheduled major gas and steam turbine outage.

<u>Slide 17: 2017 Guidance: Project Adjusted EBITDA bridge to Cash Provided by Operating Activities</u>

Slide 17 provides a bridge of our 2017 Project Adjusted EBITDA guidance range of $250 to $265 million to an estimate of Cash provided by operating activities, which we have updated to a range of $155 to $170 million, consistent with the increase to Project Adjusted EBITDA guidance. For purposes of this bridge, the impact of changes in working capital on cash flow is assumed to be nil. Our assumptions with regard to corporate overheads, cash interest payments and cash taxes are unchanged, although the recent repricing of our term loan should yield modest savings this year, net of the $1.3 million of transaction costs that will be recorded in the second quarter.

Planned uses of operating cash flow in 2017 include $100 million amortization of our term loan; $12 million of project debt amortization; $5 million of capital expenditures, mostly consisting of the Morris turbine upgrade and a few other small projects; and $9 million of preferred dividend payments. We expect to have significant free cash flow remaining after these uses that would be available for discretionary purposes. As previously noted, we plan to allocate $40 million or more of our estimated discretionary cash to additional debt reduction in 2017.

2018 Outlook

As previously discussed, our 2017 guidance represents a significant increase from our 2016 results, on the order of $55 million based on the guidance midpoint. This increase is primarily attributable to the contribution by Kapuskasing and North Bay, which will not continue in 2018 because of the expiration of the enhanced dispatch contracts at year-end 2017 and the non-recurring nature of the Global Adjustment payments received in 2017. The additional cash flows from these plants are very beneficial and will add to our cash balance and debt repayment capacity in 2017. However, we do not expect either of these plants to generate EBITDA in 2018.

We are not providing 2018 guidance at this time. However, we would note that the roll-off of Kapuskasing and North Bay would put our 2018 results at about the level of 2016 ($202 million). Other factors likely to affect results include the expiration or potential expiration of PPAs for the San Diego plants and Williams Lake in the early part of 2018, as previously disclosed. In comparing 2018 to 2016, we would expect there to be a much smaller reduction associated with PPA expirations than with the roll-off of Kapuskasing and North Bay. This reduction could be partially offset by increases elsewhere in the portfolio. From a cash flow standpoint, we would expect the impact of lower Project Adjusted EBITDA to be mitigated (although not completely offset) by reductions in cash interest payments resulting from repayment of $150 million or more of debt in 2017 and approximately $100 million of term loan and project debt in 2018.

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

Slide 18: Concluding Remarks

The IPP sector in the United States is in a period of distress with low power prices owing to weak demand, public policy (at least in some of the states in which we operate) that is supportive of intermittent power generation while not adequately compensating reliable generation sources, state-level efforts to avoid nuclear retirements, and low interest rates coupled with tax incentives creating new supply in already oversupplied markets. Many of the same factors are at play in Canada.

The good news for Atlantic Power is that our efforts to reduce debt, cut interest expenses, cut corporate overhead and extend debt maturities have put us in a position to act deliberately and with patience. Compared to 2013, our interest payments and overheads are $91 million lower, which is significant against a

Project Adjusted EBITDA this year of $250 to $265 million, and even more significant if the EBITDA related to our Ontario plants that will not continue next year is excluded.

We have improved liquidity of $214 million, including $122.5 million available under our $200 million revolver, and $91.5 million of unrestricted cash, including approximately $66 million at the parent level. We also have a growing ability to access capital markets, as evidenced by the successful term loan repricing we just completed.

We have good options for allocating our cash flow and using our liquidity, including: maintaining ownership of Piedmont with its 15-year remaining PPA life and A- credit offtaker by paying down or paying off the 2018 maturity; redeeming the 2019 convertible debentures; making capital investments in certain plants related to PPA renewal efforts; developing new projects for industrial customers, and repurchasing shares when our share price is lower than our estimate of intrinsic value per share, as is currently the case.

Although we cannot control power prices or public policy, we believe our two-year turnaround effort has put us in a better position to both endure the downturn, protecting as much value as we can in this market environment, while also looking to grow intrinsic value per share over time through rational capital allocation. If we get a stronger power market environment at some point in the future, our low corporate overheads and reduced interest expense will provide us with enhanced cash flows that will be divided by a lower share count.

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 loss on a consolidated basis is provided in Table 1 below.

Atlantic Power Corporation
Table 1 – Reconciliation of Net Loss to Project Adjusted EBITDA
(in millions of U.S. dollars, except as otherwise stated)
Unaudited

	Three months ended March 31	
	2017	**2016**
Net loss attributable to Atlantic Power Corporation	**($2.7)**	**($14.9)**
Net income attributable to preferred share dividends of a subsidiary company	2.1	2.0
Net loss	**($0.6)**	**($12.9)**
Income tax benefit	(0.3)	1.6
Loss from operations before income taxes	(0.9)	(11.3)
Administration	6.4	6.1
Interest expense, net	17.3	16.6
Foreign exchange loss	2.5	19.8
Other income, net	-	(2.5)
Project income	**$25.3**	**$28.7**
Reconciliation to Project Adjusted EBITDA		
Depreciation and amortization	$34.9	$29.9
Interest expense, net	2.4	2.5
Change in the fair value of derivative instruments	1.2	1.2
Other expense	-	0.2
Project Adjusted EBITDA	**$63.8**	**$62.5**