PREPARED REMARKS
Q2 2017
AUGUST 4, 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

I'll start by covering the highlights of the second quarter. Other members of the management team will address operational and financial results and provide an update on commercial activities and PPA renewal efforts. I'll wrap up with a discussion of how our restructuring activities to date have positioned us from a balance sheet and cash flow perspective to address the period ahead when some of our PPAs are expiring. I won't be addressing our assets or strategic positioning much this quarter, as we did that in our year-end 2016 financial results conference call in March. (The text of those remarks can be found on the Investors page of our website under "Presentations".)

Slide 4: Overview

Q2 2017 Financial Highlights

As discussed in our second quarter 2017 results press release, we recorded a net loss attributable to Atlantic Power Corporation of $(21.9) million vs. a loss of $(18.5) million for the second quarter of 2016. Results in 2017 included the benefit of the OEFC settlement as well as a non-cash impairment charge, both of which Terry will address later. Project Adjusted EBITDA of $85.4 million included a $24.7 million benefit from the OEFC settlement and was up from $46.2 million in the second quarter of 2016. Cash provided by operating activities of $50.9 million increased from $24.3 million in the second quarter of 2016, driven by higher Project Adjusted EBITDA and lower cash interest payments.

2017 Guidance

Results for the second quarter and year to date keep us on track both operationally and financially to achieve our Project Adjusted EBITDA guidance for 2017 of $250 to $265 million. We also continue to estimate cash provided by operating activities for 2017 of $155 to $170 million.

Continued Balance Sheet Improvement

During the second quarter we repaid $29.5 million of term loan and project debt, and for the year to date we have repaid $56.9 million. Our leverage ratio at June 30 of 4.4 times was significantly improved from the March 31st level of 5.4 times. We are committed to repaying $150 million or more of debt this year, which would put our year-end 2017 leverage ratio below 4.0 times.

Cash Available for Capital Allocation

At June 30, we had total liquidity of approximately $227 million, including approximately $104 million of unrestricted cash. Approximately $69 million is cash at the parent which is available for discretionary purposes. As Terry will discuss, we expect this to increase to a range of $105 to $110 million by the end of this year, assuming we do not use any of it for discretionary purposes before then.

This cash is available to us for additional debt repayment, including the Piedmont project debt maturing in 2018, the convertible debentures maturing in 2019 and discretionary repayments on our term loan. We've committed to using $40 million or more of it for discretionary debt repayment this year. Other potential uses of this cash include repurchases of common and/or preferred shares under our normal course issuer bid, internal growth (including optimization investments and PPA-related capex) and external growth. We will take a careful and methodical approach without hurry and will be guided by our price-to-value estimates both on an absolute and relative basis.

<u>Progress on Expiring PPAs</u>

As discussed in our August 1st press release, we reached agreement with San Diego Gas & Electric (SDG&E) on new contractual arrangements (seven-year tolling agreements) for our Naval Station and North Island projects in San Diego. These are subject to a couple of significant conditions, including obtaining regulatory approval from the California Public Utilities Commission (CPUC) and retaining site control beyond February 2018. But we view this as an important milestone in this process. Joe will discuss this announcement and our continuing efforts in Ontario and at Williams Lake.

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

<u>Slide 5: Q2 2017 Operational Performance</u>

We continue to place the highest priority on maintaining a strong culture of safety and regulatory compliance. Although we did have one recordable injury in the second quarter, the employee has since returned to work. For the first six months of this year, our total recordable incident rate of 0.73 was better than the most recent industry average statistic.

As we discussed on the previous quarterly call, 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. In total, generation was 23.5% lower in the second quarter than the year-ago period, primarily due to the decline in Ontario as well as lower water flows and a forced outage at Mamquam, lower merchant demand at Frederickson due to increased hydro availability in the region, and lower merchant generation at Morris due to low demand and low power prices. These factors were partially offset by increased generation at Curtis Palmer, which experienced higher water flows versus the comparable 2016 period.

Our availability factor in the second quarter of 2017 was 85.2% versus 92.7% in the year-ago period. The decline reflects lower availability at Mamquam due to a forced outage, and at Kenilworth, Morris and Frederickson, due to planned maintenance outages.

With respect to our hydro plants, conditions this year for Curtis Palmer are significantly better than in 2016. We experienced higher snowpack this winter and better rainfall this spring, which has continued into the third quarter. As a result, water flows were stronger than in the second quarter of 2016, and strong flows have continued into the third quarter.

Mamquam, which had a record year in 2016 in terms of water flows, experienced lower water flows in the first and second quarters, although fairly consistent with an average water year. We did have a forced outage in the second quarter caused by a bladder failure but made temporary repairs and returned the plant to service. Installation of the replacement bladders is scheduled for the beginning of September.

<u>Slide 6: Operations Update</u>

During the second quarter we undertook planned maintenance outages at several plants, including a major outage for both the gas and steam turbines and associated generators at Frederickson. At Kenilworth we completed an overhaul of the steam turbine. In June, we completed the last of three combustion turbine upgrades at Morris, which was an optimization project that represented the majority of our capital expenditures for this year. Following completion of the upgrade, test results showed both increased capacity and lower heat rate for the turbine.

Looking ahead, we have a fall outage planned at Cadillac, which will include replacing the plant's distributed control system.

Next I'll provide an update on two other projects that we discussed on the previous quarterly call, Tunis and Piedmont. We expect to return Tunis to service in 2018 under its 15-year PPA following receipt of any necessary permits and completion of a major gas turbine overhaul. We expect to incur approximately $6.5 million of maintenance costs related to the project that would be expensed this year, which represents most of the total $7 million expected cost. If timing of the work is delayed, some of the expenditures could slip into 2018.

With respect to Piedmont, we have made significant investments in the project since its commercial operation in 2013, consisting of both equipment upgrades and process controls, in order to improve its operating and financial performance. The plant is now operating well and earning substantially all of its capacity payments under the PPA. As a result, we are on track to see improved financial results from

Piedmont. We expect Project Adjusted EBITDA of approximately $9.5 million this year, up from $7.5 million in 2016. With continued good performance and some optimization projects that we have identified, we believe that we can improve the EBITDA to approximately $10 million.

Separately, as we mentioned on our previous quarterly call, in April the Georgia environmental authorities amended Piedmont's Title V air permit, establishing 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 was submitted to the EPA in late July, where it is subject to a 45-day comment period and EPA review before becoming final. We expect that this permit issue will be fully resolved by the end of the third quarter.

As we have discussed the past couple of quarters, this year we have been undertaking an aggressive initiative to analyze, identify and achieve potential savings in our operation and maintenance costs. Although we have made progress in analyzing these costs, and are in the process of reviewing our budgets for each of our projects, we do not yet have an estimate of potential savings from this initiative. At this point in the process, what we can say is that our fleet is reasonably efficient given the constraints posed by our small project size (about 90 MW on average) and geographically dispersed locations – which make it quite different from the portfolios of the larger U.S. IPPs. This makes benchmarking our performance quite difficult. In addition, some of our plants are in transition resulting from changes to or expirations of their PPAs. For example, three of our projects in Ontario are under agreements that do not require them to operate. The new contracts that we just announced for Naval Station and North Island are based on the two plants converting from baseload to dispatchable operation. These changes also make it difficult to establish a cost baseline from which we could provide some color on potential savings.

We have completed the budget review for one of our larger plants (from an EBITDA perspective), and have identified savings of approximately 4% in 2018. For this and some other plants, we expect additional savings as long-term service agreements expire and are not renewed. Overall, though, we do not expect to realize savings on the order of what we were able to achieve in corporate overheads. We will provide updates on this process in future quarterly calls.

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

Slide 7: Commercial Update: PPA Renewal Status

Earlier this week we announced new contractual arrangements for two of our San Diego projects. I'll discuss those as well as provide an update on developments in a couple of other key markets.

In Ontario, we continue to have discussions with the relevant parties with respect to our plants on potential initiatives that would produce ratepayer savings while also being beneficial for us.

We recently executed an amendment to the Tunis PPA that will allow the project to return to service as a simple-cycle facility. Under the amended PPA, the project will provide firm capacity, but will dispatch only when needed. We believe these changes to the PPA will reduce operating risk and make the facility more marketresponsive. As Dan discussed, we're planning to return Tunis to service next year subject to receiving any necessary permits and completing the gas turbine overhaul.

We expect that when the current enhanced dispatch agreement for Nipigon ends in October 2018, the project will return to service under the existing PPA or a revised one that would provide for a more flexible operating arrangement through the expiration of the PPA in December 2022. We will have more to report on Nipigon in the coming months.

Turning to California, as discussed in our August 1st press release, we recently executed new contractual arrangements for our Naval Station and North Island projects in San Diego with the existing customer, SDG&E. The new contracts are Power Purchase Tolling Agreements, or PPTAs, that have a seven-year term commencing as early as February 2018. The contracts are subject to two significant conditions precedent:

- **Regulatory approval**. In late July, SDG&E submitted the PPTAs and amendments to the existing PPAs (discussed below) to the CPUC for approval. This process could take approximately four months or longer.
- **Site control**. As we have discussed on previous conference calls, the existing steam contracts with the Navy expire in February 2018. These contracts provide us the right to use the property on which the plants are located. In late May, we responded to the second phase of a solicitation by the Navy for energy security and resiliency at these two sites. A successful outcome in this process is required to retain control of the sites beyond

February 2018. We are not able to estimate whether the Navy will grant us site control or how long this process might take.

The Company and SDG&E have also executed amendments to the Existing PPAs for Naval Station, North Island and Naval Training Center (NTC), which provide for termination of the existing PPAs as early as February 2018, coincident with the expiration of the Navy agreements. These amendments are also subject to CPUC approval.

We also executed Resource Adequacy (RA) contracts with SDG&E for all three of our San Diego projects. The RA contracts are also subject to CPUC approval and are conditioned upon the Company retaining site control. We believe the RA contracts for Naval Station and North Island will become effective only under limited circumstances and conditions. The RA contract for NTC would cover the period from February through December 2018. NTC is not part of the Navy solicitation for energy security and resiliency and thus the process for retaining site control beyond February is undetermined.

As disclosed in our August 1st press release, we expect that Project Adjusted EBITDA under the PPTAs for Naval Station and North Island would approximate $6 million annually on a combined basis, which we believe is reflective of current market conditions. Although this is substantially lower than the $16 million that the projects are expected to generate under the existing PPAs in 2017, we believe the PPTAs offer us an attractive return on the investment that we expect to make in the form of major maintenance and upgrades, primarily in 2018, and preserve the long-term optionality of the plants. We will provide further detail on plant investments once the conditions precedent are achieved.

Separately, we are continuing to pursue alternate contractual arrangements for NTC beyond 2019, and Oxnard, for which the PPA with Southern California Edison expires in April 2020. A new contract for NTC would be contingent on us retaining site control for this project.

Turning to our Williams Lake biomass plant in British Columbia, as we discussed last quarter, we are in discussions with BC Hydro on a potential short-term extension of the PPA, which expires next March. Although we believe that we have made progress, there are not any substantive developments to report. The short-term extension is expected to bridge the plant through completion of BC Hydro's Integrated Resource Plan (IRP) process, which is expected to commence in November 2018 but not be finalized until 2019. We expect that the IRP will address what role biomass should play in the utility's longer-term resource mix.

A short-term PPA extension would not require us to invest in a new fuel shredder at Williams Lake. This investment, which would allow the plant to burn a mix of up to 50% rail ties and other alternative fuels, would be contingent on a long-term PPA extension (or new PPA) for the project that allows us to recover our investment as well as earn a reasonable return, and favorable resolution of the appeal of the air permit that was issued in September 2016. The appeal will be heard by the Environmental Appeal Board, but the schedule has not yet been determined. We expect a decision by the Board in the first half of 2018. We believe that we have a strong position and that the permit will be upheld.

<u>Terry Ronan – Atlantic Power Corporation – EVP & CFO</u>

Slide 8: Q2 Financial Highlights

There were several factors that significantly affected results for the second quarter and the year to date, as follows:

<u>OEFC Settlement</u>. Last quarter we announced that we had reached a settlement with the OEFC regarding the Global Adjustment dispute affecting three of our projects in Ontario. Results for the second quarter included US$24.7 million of revenues under this settlement. Approximately $8 million was received in the first quarter but not recorded in revenue because of its contingent nature. In the second quarter we received another approximate $16.4 million. The settlement in April resolved all contingent aspects of the gain, so the entire $24.7 million was included in revenue, Project income, Net income and Project Adjusted EBITDA in the second quarter. Under the terms of the settlement, we expect to receive approximately $3 million of additional payments under the enhanced dispatch contracts for Kapuskasing and North Bay over the balance of the year. These will be recognized as revenue, when earned, over the balance of this year. Slide 21 of the presentation provides a summary of this information.

<u>Enhanced dispatch contracts</u>. These contracts went into effect at the beginning of this year for our Kapuskasing, North Bay and Nipigon projects in Ontario. Although revenues received under the contracts were lower than the previous arrangements, operating costs were also lower since we put the projects into a non-operational state earlier this year. In addition, in the comparable year-ago period, Kapuskasing and North Bay were purchasing gas under an above-market contract that expired at the end of 2016. The fuel and operating cost savings more than offset the lower revenues. The benefit to Project Adjusted EBITDA in the second quarter was approximately $10.8 million.

Impairments. During the quarter, we made a determination that the carrying values of two of our equity-owned projects, Selkirk and Chambers, had been impaired. The impairment, which totaled $57.7 million, did not affect Project Adjusted EBITDA or cash flow.

We own a 17.7% limited partner interest in Selkirk, which has been operating as a merchant facility since its PPA expired in August 2014. During that time the Company has not received any distributions from the project. Based on the project's history of making no cash distributions while operating as a merchant facility, the short-term and long-term operational forecast, as well as the likelihood that further investment will be required to operate the facility, we determined that our investment in Selkirk is impaired and the decline in value is other than temporary. Accordingly, during the second quarter of 2017, we recorded a $10.6 million full impairment.

During the second quarter of 2017, we also evaluated our 40% interest in Chambers for potential impairment. The significant decrease in power, gas and coal prices in the most recent long-term forecast we used to estimate discounted cash flows for the period following the expiration of the project's PPA in March 2024 had a significant negative impact on the estimated value of the project. Although we believe that power and gas prices will recover over time, we do not believe they will recover to the extent necessary to recover our pre-impairment carrying value of $124.3 million. Accordingly, we recorded a $47.1 million impairment, which reduced our carrying value to $77.2 million.

We expect to conduct our annual assessment of the carrying values of our consolidated plants and goodwill for potential impairment in the fourth quarter, as is our usual practice.

Slide 9: Q2 and YTD 2017 Project Adjusted EBITDA bridges

We reported $85.4 million of Project Adjusted EBITDA for the second quarter of 2017, an increase of $39.2 million from the $46.2 million reported for the second quarter of 2016. As previously discussed, the increase was primarily attributable to the impact of the OEFC settlement and 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 at year-end 2016. Together these accounted for approximately $36 million of the increase. Higher water flows at Curtis Palmer contributed $6.5 million of the increase. Partially offsetting these positive factors were reductions at Frederickson due to a major planned maintenance outage ($3 million) and at Mamquam ($2 million) due to lower water flows and a forced outage.

For the six months ended June 30, 2017, Project Adjusted EBITDA was $149.3 million, an increase of $40.6 million from the $108.7 million in the year-ago period. The combination of the OEFC settlement and the enhanced dispatch contracts and the expiration of the above-market gas contract for Kapuskasing and North Bay contributed $42 million to the increase. Higher water flows at Curtis Palmer contributed another $6.5 million. These factors were partially offset by lower energy and capacity prices at Morris, as well as reduced merchant generation ($5 million); lower water flows and a forced outage at Mamquam ($3 million); lower waste heat and higher fuel prices at Calstock ($3 million), and a major planned maintenance outage at Frederickson ($2 million) in the second quarter.

Slide 10: Cash Flow Results and Uses of Cash

Cash provided by operating activities of $50.9 million in the second quarter of 2017 increased $26.6 million from the year-ago figure of $24.3 million. The 2017 result benefited from the approximately $16.4 million of OEFC settlement revenues that were received in the second quarter. Other factors positively affecting cash flow were the benefit to gross margin from the enhanced dispatch contracts and the expiration of the above-market gas contract, improved hydrology at Curtis Palmer and a $4.2 million reduction in cash interest payments from the reduced spread on the term loan (effective April 2017) and lower debt balances. These favorable variances were partially offset by decreases at Frederickson and Mamquam, as previously discussed.

During the quarter, we repaid $27.1 million of our term loan and amortized $2.4 million of project debt. We also made capital expenditures of approximately $2.2 million (mostly for the combustion turbine upgrade at Morris) and paid preferred dividends of $2.2 million. These uses were funded from our operating cash flow.

For the six months ended June 30, 2017, cash provided by operating activities was $85.0 million, an increase of $31.3 million from $53.7 million in the year-ago period. Results were positively affected by the OEFC settlement ($24.7 million), the enhanced dispatch contracts and the expiration of an above-market gas contract, improved hydrology at Curtis Palmer and a slight reduction in cash interest payments. These factors were partially offset by reductions at Morris, Frederickson, Mamquam and Calstock.

During the six months ended June 30, 2017, we repaid $52.1 million of our term loan and amortized $4.7 million of project debt. We used $4.2 million for capital expenditures (representing most of the $5.5 million that we expect to make this year) and paid $4.3 million of preferred dividends.

Slide 11: 2017 Guidance: Project Adjusted EBITDA bridge vs. 2016 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.

Our 2017 Project Adjusted EBITDA guidance of $250 to $265 million is unchanged from the update we provided in our May 4, 2017 press release.

Slide 11 presents a bridge of Project Adjusted EBITDA for the latest 12 months ($242 million) to our guidance for the full year of $250 to $265 million. The primary factors affecting results in the second half of 2017 are the continued benefit of the enhanced dispatch contracts and expiration of the above-market gas contract for two of our Ontario projects and the non-recurrence of an extended planned maintenance outage at our Morris project that occurred in the third quarter of 2016, partially offset by expected maintenance costs associated with preparing our Tunis project for a return to service in 2018 under the terms of its PPA.

The slide also includes a bridge of our 2017 Project Adjusted EBITDA guidance range of $250 to $265 million to estimated Cash provided by operating activities of $155 to $170 million. For purposes of this bridge, the impact of changes in working capital on cash flow is assumed to be nil.

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.

<u>Slide 12: Liquidity</u>

At June 30, 2017, we had liquidity of $227.2 million, including $104.4 million of unrestricted cash, which is approximately $13 million higher than the March 31st level of $214 million. The increase was all in unrestricted cash. Approximately $78.6 million of the cash balance is at the parent; holding aside approximately $10 million for working capital purposes, we had about $69 million of discretionary cash at June 30.

<u>Slide 13: Progress on Debt Reduction and Leverage</u>

Our June 30, 2017 consolidated debt was $947 million. (Note, the debt totals shown on Slide 13 exclude unamortized discounts and deferred financing costs that are reflected in the presentation of debt on our balance sheet.) During the quarter, we repaid $29.5 million of term loan and project debt, as previously discussed. Since year end 2013, we have reduced our consolidated debt by approximately $930 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 4.4 times at the end of June. The significant reduction in the leverage ratio from 5.4 times at the end of March was primarily attributable to the positive impact on EBITDA of the OEFC settlement payments (recorded in the second quarter) and the increased EBITDA associated with the enhanced dispatch contracts and the expiration of the above-market gas contract in Ontario for the past two quarters, and to the continued reduction in debt. 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 55% 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 $48 million of our term loan and $7 million of project debt in the remaining six months of 2017, and expect to repay at least an additional $40 million of debt, 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 ($62.4 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 $54.2 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: 2017 Capital Allocation

Slide 15 presents a bridge of cash available at the parent for capital allocation at year-end 2016 of approximately $50 million to our estimate of the year-end 2017 level of $105 to $110 million, assuming no use of cash for discretionary purposes prior to year-end. This cash is available for discretionary debt repayment, common and preferred share repurchases under the NCIB, internal growth, including optimization projects or PPA-related investments, and external growth.

In early July, we used Cdn$2.7 million (approximately US$2 million) to repurchase 171,612 preferred shares under our NCIB. Considering the discount at which they were trading and the related tax savings, the return on this investment was approximately 11%.

Delevering remains one of our most important financial goals. Although required debt amortization in 2017 is $112 million, which is funded from our operating cash flow, we plan to allocate $40 million or more of discretionary cash for additional debt reduction. 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.

Discretionary debt repayment could include redemption of convertible debentures ($105 million US$ equivalent), repayment of the Piedmont project debt maturity ($54.2 million in August 2018), or additional repayment of the term loan. With respect to Piedmont, we're evaluating different paths to address the 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.

As Dan discussed, 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 September 2032, is with a strong counterparty with an A- credit rating. The remaining PPA term of more than 15 years is approximately triple our portfolio EBITDA-weighted average of approximately 5 years. We are expecting increased EBITDA from the plant this year with room for further improvement in the future. Although the plant has never made cash distributions, it does generate approximately $9 million of cash available for debt service annually, the majority of which is currently being applied to debt service. Reducing or eliminating the debt, which has an average rate of 8.1%, would make this cash flow available for distribution to the parent.

We view these as good options to be weighing. We are taking a careful and disciplined approach to our evaluation of this asset and the related debt maturity.

Alternatives available to us with respect to the convertible debentures include repurchases under our 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, respectively; or a refinancing of one or both prior to maturity. We also have the option of using up to $100 million under our corporate revolver to address the convertible debentures.

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

Slide 16: CEO Concluding Remarks

Over the past two and a half years, Atlantic Power has made significant progress in restructuring both the business and the balance sheet. This effort has been driven by an outstanding team of employees, including 212 at the plants and 42 in the corporate office, and they have my deepest and most sincere gratitude.

The company has paid off one billion dollars of debt and reduced corporate overheads and interest expense by a combined $91 million annually. Leverage has been reduced from a peak of 9.5 times (at year-end 2013) to an estimated 4 times (by year-end 2017). That good work has positioned us with liquidity of $227 million (at June 30, 2017), including $69 million of available cash at the parent level, which we expect will increase to approximately $105 to $110 million by year end, assuming we don't find productive ways to deploy any of it before then, which we likely will.

Looking forward from this significantly improved financial position, let me discuss our financial outlook and strategic options. Our current share price is well below our current estimates of intrinsic value (a discounted cash flow analysis of the business). We think the discount may be due to a combination of the following:

1. The substantial decline in power prices has put pressure on U.S. IPP shares generally.

2. Our hydro assets may be undervalued in our share price. We wouldn't be a seller of our very high-quality hydro assets at even 14 times EBITDA (estimated $44 million in 2017), as we think the assets are worth more than that.

3. Piedmont was a troubled start-up project but it is operating well now and we expect it will continue to do so. This year we estimate it will generate $9.5 million of Project Adjusted EBITDA, and we believe it can generate about $10 million on a normalized run rate. As Terry discussed, we now have the liquidity to pay off Piedmont's debt ($54.2 million at its August 2018 maturity) and hold the project for the long term. Or we could consider a partial refinancing of the project, or possibly run a sales process. As we discussed last quarter, the project's Title V air permit is pending, which we expect will be resolved in September (without material impact), after which time we will be able to provide more of an update.

4. Significant NOLs (approximately $619 million at year-end 2016, though some are subject to limitations on their use).

5. Post-PPA recontracting positions which are better in some of our longer-dated expirations than is the case on near-term expirations.

We have deliberately not devoted any time or energy talking up our shares. Instead, we are totally focused on generating as much cash flow as possible from our assets, and then allocating our capital wisely to maximize intrinsic value per share.

This year, 2017, is projected to be a strong year for Project Adjusted EBITDA and operating cash flow, because of the OEFC settlement and higher earnings at Kapuskasing and North Bay (approximately $70 million on a combined basis, which will not continue beyond this year). As a result, next year we expect Project Adjusted EBITDA to decline. Normalizing for PPA expirations in 2018, however, we expect that over the 2018-2022 period, Project Adjusted EBITDA should be relatively stable and substantially contracted. Cumulatively over the five years, we expect cash flows from operating activities (excluding working capital changes) of approximately $550 to $600 million.

Note, this is a multiyear estimate based on a set of assumptions, including long-term forecasts of power prices (curves) that are inherently volatile. It is not guidance and we will not be updating these numbers on a regular basis. Slide 17 provides more details on the assumptions in this estimate.

So what are our plans for this significant cash flow? There are two obvious options:

1. **Debt reduction**. We can focus our capital allocation on debt reduction and further delever the balance sheet. Term loan repayment and project debt amortization and maturities during this period total $491 million. But if we allocated all available cash to debt repayment, we'd expect to have a leverage ratio well below 2 times by the end of five years and a zero net debt position by approximately 2025.

2. **Share repurchase**. We can buy back our common and preferred shares. When I joined the Company in early 2015, I said we would try to do all the things a private equity owner would do. We have cut costs, divested assets, restructured debt and improved operational efficiency. One thing that we have not done is lever up; to the contrary, we have delevered. And we now have the financial flexibility to be an aggressive buyer of our shares if they continue to trade at the meaningful discount to intrinsic value that we believe they do. We expect to have $105 to $110 million of discretionary cash available at year-end; this compares to our current market capitalization of approximately $270 million.

To set expectations, though, our intention is to be balanced between these competing alternatives, as we have been to date. Earlier this year, we committed to using at least $40 million of this cash for discretionary debt repayment. We will continuously weigh the downside risk reduction from lower levels of leverage against the upside value capture from buying in shares at current price levels, and adjust our capital allocation as our assessment of risk versus return changes over time.

In addition, we always consider strategic options such as asset divestitures. For example, in early 2015, we saw the disconnect between the prices being paid for underlying assets and the share prices of U.S. IPP companies, and we determined that we could create meaningful shareholder value by selling $350 million of high-valued wind assets and then buying in $22 million of common and preferred shares (while also using the majority of the proceeds to strengthen our balance sheet by paying down debt). We saw better returns from making investments in our plants and buying in our shares than we saw in the external power markets. We focused on intrinsic value per share rather than on the absolute size of the business.

Considering our strengthened financial position, we are not a forced seller of anything. Given the number of U.S. IPPs whose "lever up and grow" strategy has shifted to one of "cut costs, reduce leverage and sell assets," the market values of assets may turn down from current levels due to increased supply on the market. This is a necessary part of rationalizing the sector. As always, our decisions on capital allocation and asset sales or purchases will be driven by price-to-value calculations. At one price we are a seller and at another we are a buyer.

Considering the recent news and rumors in the IPP sector about M&A possibilities, let me repeat our views on M&A. I have been involved in selling three different IPP companies, selling significant portions of power portfolio assets twice and in the demerger/spin off of an international power business. We are always comparing the value of running the business to the value of a sale of the business.

On the sales in which I have been involved, we achieved good prices in markets with bullish sentiment. Today the public share prices of U.S. IPPs seem to reflect pessimism. It does not strike me as an opportune time to be a seller. We will, however, watch the M&A activity closely to see what types of values are achieved, if in fact anything gets done.

Our plan, then, is a boring but steady one. Continue to pay off debt, manage costs aggressively, focus on efficiency across the business and allocate capital as rationally as we can. We bought in $22 million of common and preferred shares on a sporadic basis over the past 20 months and this year we will reduce debt by $150 million, including what we repaid in the first half. We can toggle toward more debt paydown or more share purchases from here and we have ample liquidity to do so. We will focus on generating as much cash flow as possible from our assets and we will be prepared to act boldly and decisively if compelling opportunities are found on or off our own balance sheet. We expect to run the business for the long term and we are excited about the ability to add value over time as value-oriented capital allocators and, when conditions are ripe, to grow the business externally as well. We have a history of selling if that creates better value for the shareholders but we hope to do that after taking the business to higher levels.

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 June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Net loss attributable to Atlantic Power Corporation	**($21.9)**	**($18.5)**	**($24.6)**	**($33.5)**
Net income attributable to preferred share dividends of a subsidiary company	2.1	2.2	4.3	4.2
Net loss from operations	**($19.8)**	**($16.3)**	($20.3)	($29.3)
Income tax benefit	(22.3)	(18.4)	(22.6)	(16.8)
Loss from operations before income taxes	(42.1)	(34.7)	(42.9)	(46.1)
Administration	5.7	5.8	12.1	11.9
Interest expense, net	18.4	51.2	35.7	67.8
Foreign exchange loss	5.9	2.6	8.3	22.5
Other expense (income), net	-	0.3	-	(2.2)
Project (loss) income	($12.1)	$25.2	$13.2	$53.9
Reconciliation to Project Adjusted EBITDA				
Depreciation and amortization	$34.7	$30.4	$69.3	$60.3
Interest expense, net	2.5	2.9	5.3	5.4
Change in the fair value of derivative instruments	2.6	(12.2)	3.8	(11.0)
Other (income) expense	-	(0.1)	-	0.1
Impairment	57.7	-	57.7	-
Project Adjusted EBITDA	$85.4	$46.2	$149.3	$108.7