PREPARED REMARKS
Q3 2017
NOVEMBER 10, 2017

<u>Ron Bialobrzeski – Atlantic Power Corporation – Manager, FP&A</u>

<u>Slide 2: Cautionary Note Regarding Forward-Looking Statements</u>

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

Slide 3: Agenda

I'll begin by reviewing the highlights of the third quarter. Other members of the management team will address operational and financial results and provide an update on commercial activities and PPA renewal efforts. Then I'll close with some remarks on intrinsic value, what the market might be missing in its assessment of Atlantic Power and what the drivers are that could affect that valuation "gap".

Slide 4: Overview

Q3 2017 Financial Highlights

As discussed in our third quarter 2017 results press release, we recorded a net loss attributable to Atlantic Power Corporation of $(32.9) million vs. a loss of $(82.4) million for the third quarter of 2016. Project Adjusted EBITDA of $77.4 million increased $26 million from $51.3 million in the third quarter of 2016, mostly because of increases at our Kapuskasing and North Bay plants in Ontario, higher water flows at Curtis Palmer and the non-recurrence of an extended planned outage at Morris in the 2016 period. Cash provided by operating activities of $52.9 million increased from $38.2 million in the third quarter of 2016, driven by higher Project Adjusted EBITDA.

2017 Guidance

As discussed in more detail later, we have increased our guidance for 2017 Project Adjusted EBITDA by $10 million to a range of $260 to $275 million. We estimate that cash provided by operating activities in 2017 will be in the range of $160 to $175 million.

Continued Balance Sheet Improvement

During the third quarter we repaid $29.4 million of term loan and project debt, and for the year to date we have repaid $86.3 million. In October, we used discretionary cash to repay $54.6 million of Piedmont project debt, reducing interest payments by $4.5 million annually. Pro forma for this repayment, our leverage ratio is 3.6 times. We expect that debt repayment in 2017 will total approximately $166 million.

Liquidity

At September 30, we had total liquidity of approximately $250 million. Pro forma for the Piedmont debt repayment in October, liquidity is $178.5 million. We also further stabilized our liquidity by extending the maturity date of our revolver by one year, to April 2022.

Cost Savings Update

In October, we repriced our term loan and revolver for the second time this year, reducing the spread by another 75 basis points to LIBOR plus 3.50%. The 150 basis point cumulative reduction since the original financing in April 2016 results in interest cost savings of approximately $8.4 million in 2018 and $33 million over the remaining term of the facilities. As I mentioned, we also repaid the Piedmont debt in October, and the 2018 interest cost savings from the two repricings and paying off Piedmont total nearly $13 million. We realized about $5 million of this already in 2017, but in 2018 we'll get the benefit of the remaining $8 million of savings.

Since year-end 2013, we have reduced debt by approximately $1 billion and have cut our corporate overhead costs by approximately 57%, resulting in nearly $100 million of annual cash savings relative to 2013 levels.

Dan Rorabaugh – Atlantic Power Corporation – SVP, Asset Management

Slide 5: Q3 2017 Operational Performance

We continue to place the highest priority on maintaining a strong culture of safety and regulatory compliance. We had no recordable injuries in the third quarter. For the first nine months of this year, our total recordable incident rate of 1.01 was in line with the industry average for 2016.

In the third quarter, generation from our plants decreased 5.7%, primarily because of a 46.0% decline in our Canada segment. As previously disclosed, we placed our Kapuskasing, Nipigon and North Bay plants into a non-operational state in the first quarter as a result of the revised contractual arrangements that we announced in January. Generation from our Frederickson plant also declined due to lower merchant demand. These factors were partially offset by increased generation at Curtis Palmer, which experienced higher water flows versus the comparable 2016 period, and at Morris, which had an extended planned outage in the third quarter of 2016.

Our availability factor in the third quarter of 2017 was 98.4% versus 91.1% in the year-ago period. The improvement reflects increases at Mamquam, which had a forced outage in the year-ago period, and at Morris and Calstock, which had planned maintenance outages in the prior period.

With respect to our hydro plants, results to date for Curtis Palmer in the third quarter were ahead of the comparable period in 2016 and also better than the historical average. This was the case in the second quarter as well. Although October was below the historical average, it was better than October of last year. The fourth quarter of last year was dry, and the year as a whole was below normal.

Mamquam had a record year in 2016 in terms of water flows. This year, it experienced lower water flows in the first and second quarters, although flows were higher in the third quarter. For the year to date, results have been close to the historical average. As we discussed last quarter, we had a forced outage in the second quarter of this year caused by a bladder failure but made temporary repairs and returned the plant to service. Installation of the replacement bladders occurred in October.

Moresby Lake also had higher water flows in the third quarter after experiencing year-over-year declines in the first and second quarters.

Slide 6: Operations Update

We had only one significant planned outage in the third quarter, which is not typically a busy outage period. We completed a replacement and upgrade of the distributed control system at Cadillac in September. We also did some work at Mamquam, as I mentioned, and Curtis Palmer, but these were not outages.

We recently received the required environmental permit for the planned restart of our Tunis plant in Ontario. Once returned to service, Tunis will operate as a simple-cycle plant under a 15-year PPA under which it would receive capacity payments for being available and would bid into the market based on its cost of production. We are targeting a commercial operation date of mid-2018. The most significant element of the restart is an overhaul of the gas turbine, which we just shipped to Houston, and an upgrade to the control system. We are finalizing the order for the new controls, so engineering will commence shortly and the equipment should be on site for installation in the second quarter of 2018. The total expected cost of the restart is approximately $6.5 million, the majority of which will be expensed in 2018.

I'll also provide an update on our initiative to analyze, identify and achieve potential savings in our operation and maintenance costs. On the maintenance side, we are particularly focused on outage intervals, and in both operations and maintenance, the implementation of best practices. We'll be holding an operations summit in November, similar to the maintenance summit we conducted in June. We're also working on an internal benchmarking of our plants, with third-party benchmarking to occur next year.

Our estimate of initial savings from this effort is modest, although we view it as just a starting point. We have identified $1 million of cost savings across the fleet that we expect to realize in 2018. In addition, we see approximately $1.5 million of avoided capital costs through 2020. We believe we can achieve these cost reductions without any adverse impact on availability or plant performance.

We will provide updates on this program in future quarterly calls.

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

Slide 7: Commercial Update: PPA Renewal Status

Slide 7 provides an update on our commercial efforts with respect to the San Diego plants and Williams Lake, all of which have PPAs or other contractual arrangements expiring in 2018. I'll also discuss commercial efforts concerning our Nipigon plant.

Beginning with San Diego, in late August we announced that we had not been selected by the Navy in its request for proposals, or RFP, for energy security and resiliency at the two naval bases on which Naval Station and North Island are located. A successful outcome in the Navy RFP was the clearest path to obtaining control of the sites beyond February 2018, when the existing lease arrangements with the Navy expire ("site control"). Site control, along with the approval of the California Public Utilities Commission, is conditions precedent of the power contracts that we executed with San Diego Gas & Electric for the two plants. Although we are continuing to pursue alternative paths to site control with the Navy, if we are unsuccessful, the three San Diego power plants (including Naval Training Center, or NTC) may cease operations as early as February 2018.

Our Williams Lake biomass plant in British Columbia is under a PPA with BC Hydro that expires on April 1st of next year. As we have discussed on previous conference calls, BC Hydro expects to file an integrated resource plan (IRP) with the BC Utilities Commission in 2018. The IRP is expected to address BC Hydro's long-term resource needs as well as the overall mix of resources. Because BC Hydro will not be able to execute a long-term contract extension at Williams Lake prior to the outcome of the IRP in 2019, we have been negotiating a short-term PPA extension that, if executed, would bridge us to that period.

If we are successful in arranging a short-term extension, we would not make material new investments in the plant during this period, instead deferring investment in a new fuel shredder until we can agree on a long-term PPA extension that provides us a return of and on this incremental investment. Under a short-term PPA extension, we would expect EBITDA to be significantly lower than under the existing PPA.

As you may recall, we applied for, and in September 2016 received, an amended air permit which would allow us to burn a fuel mix of up to 50% rail ties and other alternative fuels in a new shredder. The permit was appealed and the schedule for hearing by the Environmental Appeal Board has now been set for the second quarter of 2018. We expect the permit to be upheld when this matter is resolved sometime after the hearings are concluded.

At Nipigon, we are in discussions with the IESO and the OEFC for a revised operating agreement that would go into effect when the enhanced dispatch contract expires at the end of October 2018. If these discussions result in an agreement, we believe that it would produce savings for ratepayers while also being beneficial for us. If we do not reach an agreement by then, the existing PPA would go back into effect in November 2018. Either agreement would terminate in December 2022. We hope to have more to report on Nipigon in the near future.

The majority of our commercial efforts to date have focused on our existing assets – PPA extensions and /or restructuring of our existing PPAs to create value (such as we accomplished in Ontario earlier this year).

As we discussed on our Q4 call in February, however, in response to market trends supporting low natural gas prices, depressed wholesale power prices, and rising retail electric prices, we commenced a greenfield development effort focused on new build mid-sized combined heat and power (CHP) generation facilities located on industrial sites backed by long-term PPAs and good host credit. We believe the aforementioned market trends that underpin this effort will continue as utilities persist in making capital-intensive investments in grid infrastructure and renewables, which put upward pressure on rates for customers continuing to take power from the grid. As we have previously noted, greenfield development of new power generation plants is a time-consuming and complex process. Based on our progress to date, however, we believe we will meet our objective of building an actionable pipeline of projects within the next year or so, providing the Company with both good long-term investment opportunities and potentially valuable optionality.

With respect to external growth in wholesale power markets, we are opportunistically evaluating both asset and portfolio opportunities. In the past several years, there has been an over-supply of capital chasing power generation assets, particularly those with long-term PPAs (primarily wind and solar), resulting in returns that we consider unattractive. However, the recent shift by several IPP peers away from growth and acquisitions to delevering and consolidation has resulted in a stepped-up flow of asset divestitures, although it is too early to know whether this will result in attractive valuations in the near to medium term. We are, however, allocating more resources to evaluation of these assets, as well as to external growth more generally, including through both an internal reallocation of resources as well as one or two external hires.

Terry Ronan – Atlantic Power Corporation – EVP & CFO

Slide 8: Q3 2017 Financial Highlights

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

Enhanced dispatch contracts. As we've discussed the past two quarters, 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 PPAs they replaced, operating costs were also lower since we put the projects into a non-operational state earlier this year. In addition, in 2016, Kapuskasing and North Bay were purchasing gas under an above-market contract that expired at the end of the year. The combined fuel and operating cost savings have more than offset the lower revenues under the enhanced dispatch contracts. The benefit to Project Adjusted EBITDA was approximately $10.1 million in the third quarter and $27.3 million for the year to date.

OEFC Settlement. In the spring of this year we reached a settlement with the OEFC regarding the Global Adjustment dispute affecting three of our projects in Ontario. Most of the payments under this settlement were received in the second quarter. We received another Cdn$1.2 million in the third quarter, for a total of Cdn$34.0 million year to date. We expect to receive another Cdn$3.8 million in the fourth quarter. (Slide 27 of the presentation provides a summary of the amounts received by quarter.)

Impairments. During the quarter, we recorded impairments of our three San Diego plants totaling $57.3 million, including $18.2 million for a full impairment of the remaining intangible assets associated with the PPAs. The impairment did not affect Project Adjusted EBITDA or cash flow. The triggering event for the impairment was the outcome of the Navy RFP in August. Our proposals involving our Naval Station and North Island sites were not selected, as we disclosed in our August 28, 2017 press release. The RFP had been the clearest path to obtaining site control beyond February 2018, when the existing lease agreements with the Navy expire. The accounting impairment is based on an assumption that the plants will not operate beyond that time, although from a commercial standpoint, we are pursuing other potential avenues to obtain site control.

Our agreements with the Navy require us to decommission the facilities within a period of time after the leases expire. As disclosed in our Q3 results press release, we have accrued a $4.6 million decommissioning liability for the plants, based on an estimate made at the time the plants were acquired that has been accreted up over time. Although we are still in the process of evaluating the scope, timing and estimated cost of decommissioning the plants, our preliminary assessment is that this estimate is conservative. We believe that from a cash standpoint, the salvage value of the assets would mostly offset our cash outlays, based on our prior experience.

As a reminder, 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: Q3 and YTD 2017 Project Adjusted EBITDA bridges

We reported $77.4 million of Project Adjusted EBITDA for the third quarter of 2017, an increase of $26.1 million from the $51.3 million reported for the third quarter of 2016. The single-largest driver of the increase was 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 at year-end 2016. Together these accounted for approximately $10.1 million of the increase. The OEFC settlement contributed another $1.0 million in the quarter. Our Morris plant had an extended planned outage in the third quarter of 2016. With normal operations this year, its Project Adjusted EBITDA increased $7.5 million. Higher water flows at Curtis Palmer contributed another $3.5 million of the increase. Mamquam also benefited from higher water flows and a forced outage in the prior period that did not recur. Orlando and Williams Lake also had modest increases, and the appreciation of the Canadian dollar benefited EBITDA by approximately $1 million (non-cash translation impact). These positive factors were partially offset by very modest decreases at several other plants.

For the nine months ended September 30, 2017, Project Adjusted EBITDA was $226.6 million, an increase of $66.7 million from the $159.9 million in the year-ago period. The enhanced dispatch contracts and the expiration of the above-market gas contract for Kapuskasing and North Bay contributed $27.3 million to the increase. Revenues received under the OEFC settlement (mostly in the second quarter) contributed another $25.6 million. Higher water flows at Curtis Palmer contributed another $10.0 million. Several other plants had more modest increases, including Orlando, Morris, Williams Lake and Piedmont. The appreciation of the Canadian dollar benefited EBITDA by approximately $1.7 million (non-cash translation impact). Partially offsetting these positive factors were decreases at Mamquam (-$2.5 million), which had lower water flows and a forced maintenance outage in the first six months of the year, and Frederickson (-$2.2 million), which had higher maintenance expense than in the comparable 2016 period.

Slide 10: Cash Flow Results and Uses of Cash

Cash provided by operating activities of $52.9 million in the third quarter of 2017 increased $14.7 million from the year-ago figure of $38.2 million. 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 ($10.0 million), the non-recurrence of the 2016 Morris outage ($7.5 million), and improved water flows at Curtis Palmer ($3.5 million). These favorable variances were partially offset by a $2.2 million increase in cash interest payments (timing-driven) and approximately $5.2 million of other changes, net.

During the quarter, we repaid $25.0 million of our term loan and amortized $4.4 million of project debt. We also made capital expenditures of approximately $1.5 million and paid preferred dividends of $2.2 million. These uses were funded from our operating cash flow.

For the nine months ended September 30, 2017, cash provided by operating activities was $137.9 million, an increase of $46.0 million from $91.9 million in the year-ago period. Results were positively affected by the OEFC settlement ($25.6 million, mostly in the second quarter), the enhanced dispatch contracts and the expiration of an above-market gas contract in Ontario ($22.9 million), lower operation and maintenance expense ($16.0 million) and improved water flows at Curtis Palmer ($10.0 million). These factors were partially offset by reductions at Mamquam, Frederickson and Calstock, and by a $25 million adverse change in working capital.

During the nine months ended September 30, 2017, we repaid $77.1 million of our term loan and amortized $9.1 million of project debt. We used $5.7 million for capital expenditures and paid $6.5 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.

As disclosed in our Q3 financial results press release, we have increased our 2017 Project Adjusted EBITDA guidance by $10 million to a range of $260 to $275 million. The $10 million increase from the previous guidance is primarily the result of three factors:

- Higher water flows at Curtis Palmer than we had previously anticipated. Results for 2017 to date have been strong, and substantially better than 2016, which was a dry year.

- Initially we had budgeted certain repowering expenditures for this year, which now will either not occur or will be deferred into 2018.

- Operating cost savings at our non-operational plants in Ontario have been better than expected.

2017 has been a strong year for both Project Adjusted EBITDA and operating cash flow. However, 2018 EBITDA is likely to be significantly lower. Although we will not provide specific guidance until our fourth quarter call, we would remind you that some of this year's Project Adjusted EBITDA will not continue into next year, for the following reasons:

As we have discussed on past conference calls, the most significant contributors to this year's strong results have been the favorable impact of the revised contractual and operational arrangements for our Ontario plants and the revenues received under the OEFC Settlement. The enhanced dispatch contracts for Kapuskasing and North Bay will expire at year-end 2017, and we do not expect them to be renewed.

The OEFC Settlement consists mostly of payments related to past periods as well as an escalator provision on revenues under the enhanced dispatch contracts. The two enhanced dispatch contracts and the OEFC settlement are expected to contribute approximately $65 to $70 million to 2017 Project Adjusted EBITDA.

Second, our three plants in San Diego are expected to generate approximately $22 million of Project Adjusted EBITDA on a combined basis in 2017. Although their PPAs do not expire until December 1, 2019, the lease agreements with the Navy expire in February 2018. Unless the Company is able to achieve site control for these three facilities, they may cease operations as early as February 2018.

Third, our Williams Lake plant has a PPA that expires on April 1, 2018. It is expected to contribute approximately $16 million of Project Adjusted EBITDA in 2017. Although we are in negotiations with BC Hydro about a potential short-term extension of the PPA, we expect that a short-term extension, if executed, would produce modest levels of Project Adjusted EBITDA as compared to the existing PPA.

In total this represents an approximate $100 million reduction to Project Adjusted EBITDA in 2018 relative to 2017. Note that this figure represents the impact only of expiring PPAs. As is the case any year, there are other positive and negative variances that would affect results, including scheduled outages (negative) and escalators on existing PPAs (positive). We will provide additional color on our next conference call.

One other comment on this topic – as we discussed on our second quarter conference call, the timing of PPA expirations is lumpy. We have seven of them between year-end 2017 and September 30, 2018, so the outcomes have a very significant impact on 2018 results. The impact is also front-end-loaded, since only one of the seven PPA expirations occurs in the second half of 2018, and it is the smallest. However, there are no PPA expirations in 2019 (assuming that all three San Diego PPAs terminate early in 2018). The two in 2020 (Oxnard and Calstock) represent a relatively modest $8 million of annual Project Adjusted EBITDA. There are no PPA expirations in 2021.

Slide 12: Bridge of 2017 EBITDA Guidance to Cash provided by operating activities

Based on our 2017 Project Adjusted EBITDA guidance range of $260 to $275 million, we estimate 2017 Cash provided by operating activities in the range of $160 to $175 million. This estimate assumes the impact of changes in working capital on cash flow is nil. We expect that cash interest payments this year will be approximately $73 million, which is $6 million higher than the previous estimate, primarily because of approximately $9 million of interest rate swap termination costs associated with the Piedmont debt repayment incurred in the fourth quarter. These should be partially offset by the favorable impact on interest payments resulting from the two repricings of the term loan spread.

Planned uses of operating cash flow in 2017 include $100 million amortization of our term loan; $11 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.

Slide 13: Liquidity

At September 30, 2017, we had liquidity of $249.8 million, including $122.4 million of unrestricted cash, which is approximately $22 million higher than the June 30th level of $227.2 million. The increase was mostly in unrestricted cash. Approximately $100 million of the cash balance was at the parent; holding aside approximately $10 million for working capital purposes, we had about $90 million of discretionary cash at September 30.

In October, we used approximately $60 million of that cash to redeem the Piedmont project debt in full. We also posted a corporate letter of credit at the project. In total, this reduced liquidity by $71 million to $178.5 million on a pro forma basis, including $41 million of cash at the parent. Consolidated debt decreased to $872 million and our consolidated leverage ratio decreased to 3.6 times. With the expected decline in 2018 Project Adjusted EBITDA, we expect the leverage ratio to move back above 4 times next year, but then begin to decline again in 2019 given the magnitude of expected debt repayment during this period.

One additional comment on liquidity – in October, we extended the maturity date of our $200 million revolver by one year, to April 2022, further stabilizing our liquidity profile. We do not currently have any borrowings under the revolver, but as shown in this table, we do use it for letters of credit.

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:

- The $82 million of projected debt repayment shown for the remainder of 2017 includes $54.6 million of Piedmont debt that was repaid in October 2017. The remaining $27 million consists of expected term loan repayment and project debt amortization.

- 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 ($64.9 million U.S. dollar equivalent) mature in December 2019. Both series of convertible debentures are callable at par two years prior to their maturity dates. Alternatives available to us with respect to the convertible debentures include a refinancing of one or both prior to maturity, or calling one or both of the issues sometime prior to their maturity dates using a combination of cash and borrowings under the revolver (up to $100 million). We also can continue to repurchase the convertible debentures under our normal course issuer bid (or NCIB), up to the 10% limit. In the third quarter, we purchased a nominal amount of convertible debentures under the NCIB.

- Most of the expected debt repayment in 2018 through 2022 – other than the convertible debentures in 2019 – is for the term loan and amortization of project debt. In total, approximately 53% of our debt is amortizing (or, in the case of the term loan, repaid via the cash sweep). 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.

Slide 15: Projected Debt Balances

Slide 15 shows our projected year-end debt balances through 2022 based on the debt repayment profile shown in Slide 14. During this period we expect to repay approximately $438 million of our term loan and $79 million of project debt (including Piedmont), largely out of operating cash flow, reducing our debt level to approximately $450 million by year-end 2022, or less than half the current level. If we reduce the size of our convertible debentures by using cash, this would reduce the projected debt level further. We expect this debt repayment to 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 operating cash flow.

I'll close with an update on our NCIB, which remains in effect through the end of this year. During the third quarter, we repurchased and canceled slightly more than 93,000 common shares at an average price of $2.36. We also repurchased 250,000 Series 1 preferred shares at an approximate 38% discount to par at a total cost of Cdn$3.9 million. We also repurchased a nominal amount of convertible debentures.

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

Slide 16: Business Update

This quarter we'll provide a "mid-year" update, as we are now approximately six months past the letter to shareholders that I wrote in April and six months away from the next one. The timing is also appropriate considering recent news about M&A and consolidation in the independent power sector.

Intrinsic Value

As we've said in the past, we don't publish our estimates of the Company's intrinsic value per share. They are highly dependent on assumptions regarding, among other things, discount rates and long-term power price forecasts. We do use our best estimate of intrinsic value to inform our capital allocation decisions.

Company's Progress

Over the last three years we have sold assets, reduced debt by approximately one billion dollars, reduced cash interest payments and overhead costs by nearly $100 million on an annualized basis, and begun to pivot our growth efforts from utility customers (traditional PPAs) to industrial customers. When we commenced our delevering and cost reduction efforts a few years ago, the market was rewarding independent power companies with high levels of leverage, high overhead costs and robust growth targets. Today asset sales, delevering and cost reductions are the order of the day in our sector.

Despite being early in implementing this strategy, and making significant progress on debt and costs as I mentioned, our shares have been range-bound.

We try to focus on what we can control: debt, overhead, culture, safety processes, regulatory compliance, prudent growth strategies and acting like shareholders, not like agents. We don't spend time trying to talk up our share price. We acknowledge the Company is difficult to analyze. Eventually, though, if we are correct in our assessment of value and we do a good job executing, we believe value will be apparent and the share price will catch up.

What is the Market Missing on Atlantic Power?

What is the disconnect between the market's view and our view? At one level there isn't a big difference. As we read it, the market is saying Atlantic Power has done a good job dealing with a bad hand, they have made great strides on costs and debt but they are still levered at nearly 4 times and have to use most of their cash flow to pay down debt, PPA renewals will continue to be challenging and there is no near-term growth pipeline.

Our view is we now have very manageable debt levels and a much more favorable maturity profile than we had three years ago. We now have ample liquidity both to continue delevering and to do some opportunistic things. Although we have above-market PPAs and EBITDA is likely to decline as they roll off, we have indicated to the market that we can continue to reduce debt using the cash flow generated by the PPAs over their remaining lives, so we expect to see leverage ratios moving lower despite declining EBITDA. If we remain focused on debt reduction, we believe we can achieve net debt levels that are either very low or approximately zero in the 2025-2027 timeframe. This may be a time arbitrage investment then. But we understand that markets are unlikely to move based on 2025-2027 debt levels until we get much closer to that period.

Thinking like owners, though, we take comfort in this low to no net debt scenario. If we reach 2025-2027 and power prices have not recovered or at least shown sufficient volatility that would allow us to re-contract or hedge at higher prices in the interim and we haven't delivered on a growth pipeline, then we would have significantly lower EBITDA but little or no net debt. We'd have some still extant PPAs, we'd have the option value post-PPA of assets such as the gas plants and we'd have considerable value in our hydro assets.

An understandable response by investors to this might be, "That is all well and good. We see the progress on costs and debt. We hear you that you believe intrinsic value is significantly higher than the current share price, but that has been the case for a few years. When will the market figure it out, or what can you do to create a share price catalyst?"

As for the market figuring it out, that largely comes down to power prices, continued debt reduction and time. In our intrinsic value analysis, we look at the power price lows of the past few years, the highs and the average. We look at which assets are well positioned on a production cost basis in their markets and which are likely to be in over-supplied markets for years. The debt, overheads and PPA revenues are all relatively easy to figure out. The tough part of this analysis is what price we will receive for power post-PPA in five to ten years. The simple answer is we don't know. We don't think we have any competitive edge in forecasting commodity prices, although we do have views informed by market fundamentals. Our view is cautious due to supply and demand imbalances and current public policy preferences (for intermittent sources of power). The market may be right in its pessimism on power prices. We are managing the business to survive in lower for longer pricing environments if that turns out to be the case, and we have significant leverage to the upside if power prices move up.

Certainly, we do not expect power prices to remain unchanged over the next five years and beyond. As J.P. Morgan said, markets will fluctuate. If we get volatility, we can solidify out-year cash flows by adding hedges when prices move up. We will continue to take a creative approach to recontracting of PPAs in a down market. Our improved financial position is allowing us to make long-term oriented decisions such as paying off the 8.2% debt at Piedmont and deciding to retain (rather than sell) this asset, which is generating Project Adjusted EBITDA of $9 to $10 million under a PPA that runs to 2032 with an A-rated counterparty. That helps underpin our long-term cash flows. If we get a higher-priced power environment, we expect to see external estimates of the Company's value increase. We don't know if or when that will happen. If we continue to deliver on debt reduction – which we do control – one would expect the market at some point to re-rate the Company based on a lower risk profile.

Over time, then, things we control (delevering and growth) and things we don't control (power prices) may close the gap between our estimates of intrinsic value per share and Mr. Market's view.

We can and will continue to execute on our balance sheet, operations and growth efforts, and then time will tell. Usually, however, when investors ask about surfacing value, or what management can do for shareholders, they mean what can we do to move the share price *now*?

Other than the things I've discussed already, we could try to improve our share price by paying a cash dividend (and we get this advice from time to time from our individual shareholders). However, paying a dividend out of cash flows generated by a set of assets that will become more sensitive to power prices (as PPAs expire) generally leads to unsustainable dividends. Furthermore, most of this cash flow is contractually allocated to debt repayment – so paying a dividend from the remaining discretionary cash flow would reduce the cash available for other purposes such as growth or share repurchases. We think we would get little credit in the marketplace for a dividend given this backdrop. When we stopped paying a dividend in February 2016, the share price went from a closing low of $1.65 to a high of $2.70 fourteen months later, indicating the market saw more value in allocating capital to other uses. This is one instance where our view coincided with the market's view.

Alternatively, we have been buying back shares, which is more tax-efficient than ordinary cash dividends. Our view of share buybacks is not determined by what messages they send or what institutions are pushing for one way or the other. Our view of share buybacks is based on price to value. We compare the market price of the shares to our estimates of intrinsic value. If the shares are selling below intrinsic value, we can add value for remaining shareholders by buying back shares. If the shares are fully valued or overvalued, we will stop allocating capital to share purchases. At one price we are a buyer and at another price we might issue shares.

How do we balance between share buybacks and debt reduction? If we had low leverage already, instead of prioritizing debt repayment we could have used our cash to tender for a significant number of shares. But because we are not at low leverage levels, we have allocated the majority of our capital to debt reduction. Again, that is not to favor debtholders over shareholders, but rather because as equity owners we view debt reduction as a prudent way of structuring the balance sheet to handle both near-term PPA expirations and the possibility of a lower for longer power price environment. We have allocated some cash to share repurchase, approximately $20 million under the NCIB programs that we've had in place, most of it during 2016. Debt repayment during this period was multiples of that, so our leverage metrics and net debt levels improved.

The decision on allocating capital between repurchasing shares and repaying debt, then, includes among other things: the level of debt we deem prudent for the business, our estimates of intrinsic value per share and the current share price. Our $20 million of repurchases were done at an average price ($2.42) close to current trading levels. We think that continuing opportunistic purchases under the NCIB is a sound approach. We do, however, want to maintain enough dry powder/capital to allow us to step up and make a larger share repurchase in the event of a significant correction in the stock, the sector or the market.

Another potential way to move the share price in the near term is a sale of the Company. Insiders have been significant buyers of shares the last two years, as has the Company. Those purchases are based on our view of price to value. Over the course of my career, I have been involved in selling three IPP businesses but we always sold when markets were frothy, not when they were depressed.

Currently, we don't see a good opportunity to sell the Company for full value or better, so we will try to create value by running the business as if all our families' financial net worth was invested and we were never going to sell it. That means: continue to pay down debt for now, spend money like a frugal owner, build a culture of servant leadership and work hard to find opportunities to grow (as the team has in the past), but always comparing growth to the returns available on our own securities, including the common shares. As shareholders we want to focus on intrinsic value per share, not in growing the absolute size of the business if that is not the most attractive use of capital.

<u>How Do You Grow the Business?</u>

Another question that investors ask is, "Now that the turnaround on cost and the management of the right side of the balance sheet has stabilized the business, how are you going to start growing the business again?" Again, we will always focus on intrinsic value per share as opposed to absolute growth in the size of the business. We want to act like owners, not like agents. Much of the damage we have seen inflicted on shareholders in the power business in the last thirty years has come from management teams laser focused on external growth and the absolute size of the business. As Warren Buffett has noted, if the CEO wants to do deals, the pro forma numbers generated will tend to support that view of the world. Growth has to be in projects that earn more than the cost of capital based on conservative assumptions. The second hurdle is that they have to have higher returns than other available uses such as share repurchases. Otherwise, growth is maximizing size but not value.

Having laid out these parameters, we do think we can grow the business again. Over thirty years this management team has invested in billions of dollars of projects and successfully grown numerous power businesses. However, we will not chase growth. We have a generally pessimistic view on merchant power investments. In the past we have grown businesses centered around Qualifying Facilities in the 80's, merchant CCGT in the 90's and wind in the 2000's. Today we have pivoted our attention to industrial customers. Electric demand growth has been sluggish and utility business models are challenged. Public policy has supported intermittent resources while probably not adequately considering the apples to apples costs of different types of generation. We don't know when that will change. Higher costs to retail and industrial users in the midst of sharply falling wholesale energy prices may cause some pressure for change. But we don't want to bet on the timing of public policy one way or the other.

We do think there is value to be added by helping industrials take advantage of declining energy prices that are not reflected in their utility bills. Therefore, we are focusing our greenfield development efforts on small industrial Combined Heat and Power projects. It will take a year or more to develop meaningful evidence on our ability to grow a pipeline in that area.

Meanwhile, we are opportunistic investors. This management team sold wind companies in 2005 and 2008 and then $350 million of wind projects at Atlantic Power in 2015. In 2008 and 2015, prices dropped shortly after our sales. At 14 times cash flow we are inclined to sell wind assets, as a hypothetical, and we'd be happy to buy them back at 7 times. Over the last few years wind and solar have been the glamour investments in power – therefore, returns have been modest.

Coal, biomass and merchant power have been the Benjamin Graham cigar butt investments of power investing. For us, it is all about price to value, not glamour or popularity. Some things can be great technologies but terrible investments (see airlines until recently, but the jury is still out there). Some things that are unloved or overlooked can provide outsized returns.

So we have an organic greenfield development effort and an ongoing opportunistic investment effort and a management team that has been successful in a series of power company growth efforts over the last thirty years. In the previous IPP companies we followed a "fix it, grow it and then sell it" model. Those were private companies. We think we have completed the "fix it" phase at Atlantic Power. We are now focused on the "grow it" phase.

We like investing. We just want to be very shareholder-oriented and rational when it comes to investing and growing. We want to guard against the excitement, emotion and ego that can drive you into bad investments or overly optimistic growth strategies. We need to be as rational as possible in comparing our capital allocation alternatives. To that end, we have been rebuilding the growth team internally with some reallocation of resources and even some external hiring, as Joe Cofelice discussed.

In terms of financial capability, we have $178.5 million of liquidity even after repaying the Piedmont debt in October. We can continue to reduce the term loan and project debt through the sweep and amortization, while still having liquidity to allocate for growth, our convertible debenture maturities and share repurchases under the NCIB. Against a $280 million market cap that flexibility is significant. Our size is an advantage in this regard. We can do smaller deals than the major IPPs and they would still move the needle for us on valuation. Getting away from where most of the capital is focused is a better place to be, to paraphrase Harry Chapin.

We are not wide-eyed optimists, obviously, but we believe we have the resources, the team, the experience and now the financial strength to start building the business again.

Conclusion

Long term we think our downside risk is now contained due to the restructuring of the last several years. As noted, if we focus our cash flow on debt reduction, we should be able to get to 2 times levered or even zero net debt in the 2025-2027 time frame, despite declining EBITDA from expiring PPAs (assuming that power prices remain low during this period). In that scenario we'd have lower EBITDA, but also much lower debt levels, and even a modest degree of success on growth would have a more meaningful impact because the denominator would be smaller. We think that even in a tough power market, this would be an attractive position in which to find ourselves.

Again, near-term catalysts such as higher power prices or improved sentiment in the power sector are not in our control. But if we see significant price moves or changes in asset or securities prices we will be prepared to move quickly. So while we are prepared to grind it out through a lower for longer scenario paying down debt and opportunistically buying in shares or investing in growth, we will be surprised if we don't see significant price volatility or compelling opportunities on the buy or sell side over the next two or three years.

In the interim this update is intended to let you know how we think about the business, so you can decide if you are a like-minded investor willing to accept the lower for longer time arbitrage scenario, potentially (or, in our estimation, probably) punctuated by high levels of volatility that will provide us with opportunities to act quickly and decisively as a buyer or seller.

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 September 30,		Nine months ended September 30,	
	2017	**2016**	**2017**	**2016**
Net loss attributable to Atlantic Power Corporation	**($32.9)**	**($82.4)**	**($57.5)**	**($116.2)**
Net income attributable to preferred share dividends of a subsidiary company	(0.8)	2.1	3.5	6.4
Net loss from operations	**($33.7)**	**($80.3)**	**($54.0)**	**($109.8)**
Income tax (benefit) expense	(15.9)	2.6	(38.5)	(14.2)
Loss from operations before income taxes	(49.6)	(77.7)	(92.5)	(124.0)
Administration	5.5	5.7	17.6	17.6
Interest expense, net	13.8	20.0	49.5	87.9
Foreign exchange loss (gain)	9.4	(3.4)	17.7	19.1
Other income, net	-	(1.7)	-	(3.9)
Project loss	**($20.9)**	**($57.1)**	**($7.7)**	**($3.3)**
Reconciliation to Project Adjusted EBITDA				
Depreciation and amortization	$36.6	$30.4	$105.6	$90.8
Interest expense, net	2.5	$2.8	8.0	$8.2
Change in the fair value of derivative instruments	2.0	($9.0)	5.8	($20.1)
Other (income) expense	(0.1)	($0.5)	57.6	($0.4)
Impairment	57.3	84.7	57.3	84.7
Project Adjusted EBITDA	**$77.4**	**$51.3**	**$226.6**	**$159.9**