PREPARED REMARKS
Q4 and YE 2017
MARCH 2, 2018

Ron Bialobrzeski – 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 annual report on Form 10-K, 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

Slides 4-5: 2017 Highlights and Recent Developments

Since we reported both fourth quarter and full year 2017 results, I'd like to do a more extensive review of the year as well as a look forward to 2018. In 2017 we made significant progress on the business fundamentals, including:

Balance Sheet:

In 2017 we paid down $166 million of debt, and ended the year with a leverage ratio of 3.3 times, down from 5.6 times at year end 2016. We also successfully repriced our term loan twice, reducing the spread by 150 basis points since the initial April 2016 financing, to 350 basis points over LIBOR. The cumulative estimated savings over the remaining lives of the facilities is approximately $33 million. We also extended the maturity date of the revolver by one year, to April 2022. Subsequent to year end, we issued a new convertible debenture with a 6.00% coupon and seven-year maturity, and used the proceeds to redeem all but Cdn$24.7 million of our 2019 convertible debentures.

Over the past four years we have reduced debt by more than $1 billion, reduced the leverage ratio from a high of 9.5 times to the current 3.3 times, reduced annual interest payments by approximately $68 million, upsized and extended the maturity of our term loan, and refinanced 2019 convertible debentures with 2025 convertible debentures. The cumulative effect of these actions is a stronger balance sheet, lower cash interest costs and an improved debt maturity profile. As a result, one agency has increased our credit ratings twice and another once. This effort was not aimed at paying off our lenders early, or favoring creditors over shareholders. Its purpose was to provide us the stability to deal with extended downturns in a commodity cyclical business and to allow us to allocate capital to other purposes without the risk of undue leverage.

Capital Allocation:

In addition to the more than $1 billion of debt repayment over the past four years, we also allocated approximately $20 million to repurchases of common stock and approximately $3 million to repurchases of preferred shares (with a par value of Cdn$6.25 million). As always, we were guided by the price-to-value relationship. In addition, we paid $11 million in common dividends in 2015.

In allocating capital we make decisions as rationally as we can, with a keen focus on reducing risk while prioritizing the highest-return uses, either internal or external. In 2017, our improved balance sheet and stronger cash position allowed us to pay off the $54.6 million of remaining project debt at Piedmont. We had considered selling Piedmont but decided that retaining ownership was preferable as the debt represented a multiple of only about six times normalized EBITDA. The debt-free project has a PPA that runs through 2032 and made a distribution to the parent for the first time in the fourth quarter of 2017. We also have made offers to buy other generation assets that we believe would be enhanced by our operating capabilities, but to date have not been successful.

<u>Costs</u>:

We continue to focus on the cost side of our business, with a view toward being as efficient as possible. From $54 million in 2013, we reduced corporate overheads to $23 million in 2016 and $22 million in 2017. The big cost reductions are behind us now. In fact, we expect to add a bit to costs as we gear up to look more at external growth opportunities, including adding a VP of Business Development we hired recently. We keep grinding away on costs, however, and in 2017 we eliminated seven positions for estimated savings of $1.2 million annually and further reduced our property and casualty insurance costs, bringing the total annualized reduction for this expense to more than $2 million since 2013.

<u>Operations</u>:

In 2017, we installed predictive analytics software at three of our projects and we are rolling it out to another three this year. We also were able to reduce our overall fleet fuel usage (on a load-adjusted basis) by more than 3% in 2017, resulting in estimated fuel cost savings of approximately $3 million.

<u>Power Purchase Agreements</u>:

Our existing long-term contracts have power prices well in excess of current market rates. As those PPAs roll off, we will experience significant declines in Project Adjusted EBITDA. Our Commercial Operations team is working diligently to extend or replace those PPAs with near-term expiration dates, and to maximize the value of existing PPAs, as Joe Cofelice will discuss in a later section of the prepared remarks. The efforts of that team resulted in some real win-win outcomes for the Company and our customers in 2017 (particularly in Ontario), as was evident in the high level of Project Adjusted EBITDA we booked for the year.

In December, we executed a new Long-Term Enhanced Dispatch Contract for our Nipigon project and a short-term extension for our Williams Lake project. We were successful in obtaining new PPAs for all three of our San Diego projects, but at this time have not been able to achieve site control at the projects with the relevant entities, which is also discussed in more detail later.

<u>Growth</u>:

In 2017, we allocated our capital predominantly to debt repayment, modest repurchases of equity securities and internal uses. The estimated returns from repurchases of equity and internal projects have been higher than the market-clearing prices for investment in new wind, solar or gas-fired generation projects and higher than returns available in the M&A market for power assets in general. We have an ongoing combined heat and power (CHP) development effort focused on industrial customers, which can capture value for customers who, because industrial rates are sticky, have not been able to benefit from the declines in natural gas or wholesale power prices. As we have said in the past, these efforts have very long lead times, in some cases taking several years to work from a marketing proposal to site evaluation specifics to agreements with customers to permitting efforts. We have nothing imminent to report on this front.

Separately, we have bid on assets in the market that have the prospects of higher returns due to technologies that are less popular or which we think our operations team can run more efficiently to increase normalized project EBITDA run rates. We have nothing imminent to report on this front either, but when we decide to do something we can move quickly.

<u>Slides 6-7: Outlook for 2018 and Beyond</u>

Looking forward to 2018 and beyond, on the key areas discussed above we can say:

<u>Balance Sheet</u>:

Coming out of 2017 we have lower absolute debt levels, a longer maturity profile, improved credit ratings and stable liquidity via cash and the revolver.

<u>Capital Allocation</u>:

With Project Adjusted EBITDA declining significantly in 2018 as PPAs expire or step down in terms, we need to remain disciplined on the debt side of the balance sheet. We expect to pay off another $100 million in debt this year, but our leverage ratio may move into the high four times range because of lower EBITDA. However, we expect it to begin declining again in 2019 and beyond as debt repayment continues at a significant pace while PPA-related reductions in EBITDA are considerably more moderate.

At year end 2017, we had approximately $40 million of discretionary cash and another $120 million of revolver availability. We have an NCIB in place which allows us to purchase up to 10% of our common shares outstanding and up to 5% of our preferred shares outstanding using discretionary cash.

In addition to the current NCIB, from time to time we may repurchase our securities through open market purchases. For example, a substantial issuer bid (SIB) is another option available to us to purchase securities and would allow us to tender for common shares or preferred shares without being subject to the aggregate percentage limits or daily volume limits imposed by the NCIB. However, an SIB requires a 35-day offering period and generally a premium to the market price, whereas the NCIB would allow us to purchase in the market immediately at the market price.

Unfortunately, when our common shares recently hit 52-week lows we were unable to buy shares at a level we consider value-accretive as we were in a blackout period due to our recent convertible debenture offering which then overlapped with our self-imposed blackout period for earnings results.
Once we emerge from the blackout period, we can make purchases of common or preferred shares using the NCIB and have the option to undertake an SIB if that becomes a more attractive alternative.

Costs:
Although we don't see step changes to our corporate or operating cost structures from these levels, we remain focused on improvements where possible. When we moved the corporate office from downtown Boston to Dedham, Massachusetts, we cut our annual rent from roughly $1 million to $500,000. We recently agreed to a reduction in space and extension of the lease in Dedham that will reduce our annual rent to approximately $250,000, despite a rising rate market.

Operations:
The operations team has identified recurring annual maintenance cost savings of approximately $2 million for 2018. In addition, they have taken out another $2 million of planned expenditures from future years.

PPAs:

The current status of our efforts with respect to expiring PPAs is discussed in a later section of these prepared remarks, though I'll make a couple of additional points here. If you follow the industry or the Company at all, you know that older PPAs (such as ours) have higher prices than the current market offers. The steps we have taken on costs and debt put us in a better position to withstand lower PPA rates. Second, although we are sometimes compared to the U.S. IPPs or merchant generators, we would note that they have little PPA coverage remaining, certainly less than ours. We have a weighted average remaining PPA life of approximately seven years based on expected 2018 EBITDA contribution.

During this period, if we remain disciplined on debt repayment, our debt should decline faster than our EBITDA, resulting in a declining leverage ratio. Although investors may focus on the declining EBITDA profile, we view the above-market PPAs as an asset providing us with cash to allocate over the coming years. We have noted in previous disclosures that we believe we can get to net debt of approximately zero by about 2025 if we achieve our debt reduction targets, and without heroic assumptions regarding expiring PPAs. At that point we'd have lower EBITDA but little (or no) net debt, hydro assets with long remaining physical and economic lives, cash flow from PPAs with remaining term, and option value from some of the combined cycle gas turbines (CCGTs) that are not currently generating revenue.

Growth:

External growth remains difficult for a value investor in the power sector. Investments in new wind and solar projects have single-digit unlevered returns and are heavily tax-driven. We are not a significant taxpayer, so we don't have an appetite for tax credits. We want to be careful to invest only where we believe we can generate owners' earnings in excess of our cost of capital. Also, having been in the power business for more than thirty years, we understand the volatility of returns from IPP assets and we require a margin of safety to invest. The internal investments we have made in our own fleet and in our own securities over the past three years appear to have much higher returns than external uses and they are in assets we understand intimately. Still, we are active in looking for external investments. We have made offers but have not bought anything yet. We will be patient and disciplined. Sometimes not doing anything is the best investment decision when markets are fully valued.

Valuation:

We remain focused on intrinsic value per share or the Net Present Value of our future cash flows. In our intrinsic value work, we make assessments about multiple factors that affect the outcome. We use a range of forward curves, but in general we expect power prices to recover modestly from current levels. Movements in power curves or changes in discount rates have significant impacts on our overall estimates of value, as do other factors. Rather than focusing on a point estimate, however, we develop a range of estimates reflecting the variability of some of the inputs. We try to be as realistic as possible to avoid fooling ourselves. Of course, we can be wrong. But based on our current base case estimates of intrinsic value, we view the recent share price weakness as a buying opportunity.

Dan Rorabaugh – Atlantic Power Corporation – SVP, Asset Management

Slide 8: Full Year 2017 Operational Performance

Beginning with our safety record, we had one recordable injury in the fourth quarter and three over the course of the year. Although the injuries were relatively minor, and only one of them resulted in lost time from work, we are committed to better performance, as we place the highest priority on maintaining a strong culture of safety and regulatory compliance. For the year, our total recordable incident rate was 1.16, which is generally in line with the industry average.

Rather than focusing on the fourth quarter operations results, since this is a yearend review I'll address the full year results and then just point out a few data points specific to the fourth quarter.

In 2017, generation from our projects decreased 15.2%, primarily because our Kapuskasing, Nipigon and North Bay projects are not in operation, per the terms of the revised contractual arrangements that we announced in January 2017. On a comparable basis excluding these projects from the 2016 numbers, generation was up slightly less than 1%. Although Mamquam generation declined due to forced outages and lower water flows, and Selkirk experienced lower merchant dispatch (before we sold it in November), these negative factors were mostly offset by increased generation at Curtis Palmer, which had higher water flows than in 2016, and at Morris, which underwent an extended planned outage in 2016.

Our availability factor in 2017 was 90.3% versus 93.3% in the year-ago period. The decrease reflects planned maintenance outages at Frederickson and Kenilworth and forced outages at Mamquam and Williams Lake in 2017, partially offset by an improvement at Morris, which had an extended planned outage in 2016.

With respect to our hydro plants, Curtis Palmer experienced strong water flows, which benefited generation relative to 2016, which was a dry year. Generation increased 41% from 2016 and was 19% higher than the historical average. Mamquam had record flows in 2016 while 2017 was much closer to average. Mamquam also had forced outages in the second quarter of this year caused by a bladder failure; we installed replacement bladders in October.

Slide 9: Q4 2017 Operational Performance

In the fourth quarter, generation declined 4% versus the year-ago period, again primarily because of the non-operational status of three of our Ontario projects. On a comparable basis, generation increased 15%, primarily because of significantly higher generation from Frederickson due to colder temperatures; increased generation at Curtis Palmer due to higher water flows (up 46% compared to a dry fourth quarter in 2016), and increased demand in PJM, which benefited our Morris project. Mamquam generation declined because water flows were close to average as compared to well above-average levels in the fourth quarter of 2016. Availability for our fleet improved to 96.1% from 93.0% in the fourth quarter of 2016 because of a forced outage at NTC in the comparable period and maintenance outages at Mamquam and Oxnard in the year-ago period.

Slide 10: Operations Update

Work to return our Tunis project to service is well under way, and we are targeting a third quarter 2018 commercial operation date. As I indicated last quarter, the most significant aspects of the restart effort are an overhaul of the gas turbine and a replacement and upgrade of the control system. Work on the gas turbine overhaul is complete and the unit is on its way back from Houston. The estimated cost of the restart is approximately $5 to $6 million. We expect to expense the majority of these costs in 2018.

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. Although we expect Tunis' Project Adjusted EBITDA to be negative in 2018 because of the restart costs, going forward we expect it to generate approximately US$2 million annually under the PPA.

In terms of other maintenance work this year, we have a major gas turbine outage scheduled at Manchief this spring, probably about six to seven weeks in duration. You may recall that we had a similar outage in the spring of 2015, which was for the other gas turbine at Manchief. We also have a shorter and less significant gas turbine outage scheduled at Kenilworth, which is scheduled for late March. There are several other maintenance projects planned that are smaller in scale.

In previous quarters we've talked about our ongoing initiative to analyze, identify and achieve potential savings in our operation and maintenance costs. Last year we held maintenance and operations summits for our employees in those areas, with a focus on outage frequency, extending maintenance intervals where feasible, and sharing of best practices in order to achieve cost savings and improved performance. We've undertaken internal benchmarking of our projects and expect to undertake benchmarking with a third party later this year.

With our 2018 project budgets completed, we were successful in implementing $2 million of non-fuel permanent cost reductions for this year. We also eliminated $2 million of planned maintenance spend from future years. In addition, we reduced one-time costs by $1.6 million, primarily related to the restart of Tunis.

We also were able to reduce our overall fleet fuel usage (on a load-adjusted basis) by approximately 3% in 2017, resulting in estimated fuel cost savings of approximately $3 million. We achieved this by fine tuning equipment efficiencies identified from performance monitoring (gas meters, gas turbine performance degradation) and project improvements.

One of the steps we took in 2017 was to deploy Predictive Analytic software at three plants, which monitors equipment and systems, with a goal of improving reliability, reducing downtime and achieving fuel and operation and maintenance cost savings. We expect to deploy this technology at another three sites this year.

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

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

Slides 11-12: Commercial Update: PPA Renewal Status

Slides 11 and 12 provide an update on our commercial efforts with respect to those projects with PPAs or other contractual arrangements expiring in 2018, specifically the San Diego projects, Williams Lake and Kenilworth. I'll also provide an update on recent developments affecting Nipigon.

Nipigon

Since January 2017, Nipigon has been under an enhanced dispatch contract with the Ontario Independent Electricity System Operator (IESO). During this time the original PPA, which has an expiration date of December 2022, has been suspended. In December 2017, we entered into a new Long-Term Enhanced Dispatch Contract (LTEDC) with the IESO for the period November 1, 2018 through December 31, 2022. As a result of this new agreement, the original PPA will be terminated effective October 31, 2018.

Under the LTEDC, Nipigon will return to service in November as a flexible simple-cycle plant. It will receive monthly capacity-type payments, and in addition will earn energy revenues for those periods during which it operates (although its capacity factor is expected to be low). The new contract structure is expected to result in improved economic outcomes for both Atlantic Power and ratepayers as compared to the original PPA.

Williams Lake

Our Williams Lake biomass project in British Columbia is operating under a contract with BC Hydro that was scheduled to expire on April 1 of this year. In December 2017, we amended and extended that contract to June 30, 2019, or September 30, 2019 at the option of BC Hydro. The amendment and extension, which commences April 2, 2018, is subject to regulatory approval, and may be terminated by BC Hydro if regulatory approval does not occur.

The short-term extension is expected to bridge operations of the facility until the outcome of BC Hydro's Integrated Resource Plan (IRP) process, expected in the second or third quarter of 2019. The IRP is expected to address BC Hydro's long-term resource needs as well as the overall mix of resources, and will take into consideration the availability of wood waste in the province and input from the forestry industry and the provincial government. The outcome of this process is expected to have a major impact on our ability to continue operations at Williams Lake over the longer term.

We are not permitted to burn rail ties during the extension period of the contract. As such, we will not make any additional capital investment in the project during this period. We expect that revenues under the contract will substantially cover our fixed operating costs. However, the cost of fuel is a major variable affecting the economics under the short-term extension. The availability and price of fuel have been affected by recent wildfires in the region and other factors, and so are difficult to forecast beyond the very near term. Based on those near-term indications, we expect that the Project Adjusted EBITDA contribution under the short-term extension will be de minimis. We will provide an update on our next quarterly conference call. We also would note that Williams Lake is operating under the original contract terms in the first three months of this year, and we expect Project Adjusted EBITDA during this period to be relatively consistent with past performance.

Separately, written hearings on the appeal of the amended air permit for Williams Lake, which we received in September 2016, are scheduled to commence later this month. The hearings will be before the Environmental Appeal Board. We expect the permit to be upheld when this matter is resolved sometime after the hearings are concluded. The amendment allows us to burn a mix of up to 50% rail ties and other alternative fuels. As previously indicated, we would not install a new fuel shredder at Williams Lake (which would be necessary to burn the different mix) until we had reached an agreement with BC Hydro on a long-term contract for the project that provided us a return of and on our incremental investment in the project.

San Diego Projects

As previously indicated, our three projects in San Diego ceased operations on February 7, 2018 upon expiration of our land use agreements with the U.S. Navy. Although we are continuing to pursue potential alternative paths with the Navy that would allow us to remain on the sites, these alternatives are complicated, and vary by site. Any potential agreement with the Navy for one or more of the sites also would need to work with our new PPAs. Unless we can agree on workable paths forward with the Navy, the projects will not return to service.

As a reminder, last summer we executed new seven-year Power Purchase Tolling Agreements (PPTAs) with San Diego Gas & Electric for Naval Station and North Island. These contracts and related agreements were filed with the California Public Utilities Commission (CPUC). On March 1, 2018, the CPUC approved (i) the early termination of our existing PPAs for all three projects; (ii) the new PPTAs for Naval Station and North Island, and (iii) Resource Adequacy (RA) agreements for 2018 for all three projects. These approvals are subject to a 30-day appeal period. As previously indicated, though, the new contracts and the RA agreements require that we achieve site control with the Navy.

We also entered into a new seven-year PPA with Southern California Edison (SCE) for NTC (also known as MCRD). The contract has a start date of January 2019. This agreement was filed with the CPUC in November 2017 and we expect the CPUC to act on this agreement in the next month or so. As previously noted, we currently do not have site control for NTC.

Kenilworth

The PPA with Merck at our Kenilworth project is scheduled to expire on September 30, 2018, though the contract has provisions for up to three one-year extensions at Merck's option, on similar terms. The Company is exploring both short- and long-term alternatives with Merck. We expect to have more to report soon, but our current expectation is that the parties will proceed with a one-year extension while Merck considers its longer-term options.

Other Commercial Initiatives

Our commercial efforts are not limited to near-term PPA expirations, but more broadly on maximizing the value of our existing assets and sites, as well as pursuing growth opportunities where they make economic sense. For example, we have commenced a marketing effort for our two mothballed gas-fired projects in Ontario, starting with North Bay. Although these two plants are currently uneconomic in the difficult Ontario wholesale market, we believe they might be competitive selling directly to industrial customers that have electricity and steam (heat) needs. Attracting new industrial customers to these locations will take time, so we do not expect to have anything to report on this effort in the near term.

As we have discussed in previous conference calls, in response to high industrial power prices and low natural gas prices, we are engaged in the green-field development of "behind the meter" new combined heat and power projects (CHP). CHP development is a time-consuming and complex process and we have nothing new to report at this time.

As for potential acquisitions in the wholesale power generation market, we believe that returns across most power asset classes are too low relative to project and market risks. That said, we are evaluating opportunities with a strong focus on out-of-favor assets with some remaining PPA life where we have operational and commercial expertise. As previously noted, we are devoting more resources to these efforts, and we remain active but disciplined in our approach.

Terry Ronan – Atlantic Power Corporation – EVP & CFO

Slide 13: Q4 and FY 2017 Financial Highlights

Slide 13 summarizes our financial results as well as the progress we made in 2017 in strengthening our balance sheet, improving our debt maturity profile, and managing our interest costs and risk. I'll review these briefly here and then go into more detail:

- Project Adjusted EBITDA results for the fourth quarter and the year were strong, and put us above the upper end of our 2017 guidance range of $260 to $275 million. Cash provided by operating activities also exceeded our estimate.

- We repaid $166 million of debt in 2017 and reduced our leverage ratio at year end to 3.3 times. We ended the year with liquidity of $198 million, including approximately $40 million of discretionary cash.
- We redeemed our only 2018 maturity (Piedmont) and extended the maturity date of our revolver by one year (to 2022). In January of this year we issued convertible debentures with a 2025 maturity, using the proceeds to redeem most of our 2019 convertible debentures. As a result, we have an improved debt maturity profile.
- We continued to reduce our interest costs, through continued debt repayment and repricing the spread on our term loan twice, to 350 bp from 500 bp over LIBOR previously. We also put on additional interest rate swaps in January of 2018 so that the floating rate exposure on our term loan is minimal in 2018.

Slide 14: Q4 and FY 2017 Project Adjusted EBITDA bridges

Fourth quarter 2017 results of $62.2 million increased $19.9 million from the fourth quarter of 2016. Full year 2017 results of $288.8 million increased $86.6 million from the 2016 level and exceeded our guidance range of $260 to $275 million. As we have been discussing throughout 2017, there were several factors that positively affected our results, including:

Enhanced dispatch contracts. These contracts went into effect at the beginning of 2017 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 at the beginning of 2017. In addition, in 2016, Kapuskasing and

North Bay were purchasing gas under an above-market contract that expired at the end of that 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 $13.5 million in the fourth quarter and $41.6 million for the year to date. It should be noted that the contracts for Kapuskasing and North Bay expired at year end 2017, and we do not expect either project to contribute to Project Adjusted EBITDA in 2018.

OEFC Settlement. In the spring of 2017 we reached a settlement with the OEFC regarding the Global Adjustment dispute affecting three of our projects in Ontario. The benefit to revenues and Project Adjusted EBITDA was $3.0 million in the fourth quarter of 2017 and $28.6 million for the full year. Most of the cash from this settlement was received in 2017, with the final $2 million received in January of 2018. (Slide 32 of the presentation provides a summary of the amounts received by quarter.)

Higher water flows at Curtis Palmer. As Dan indicated, Curtis Palmer benefited from higher water flows in 2017, both as compared to 2016 and the long-term average. Project Adjusted EBITDA increased $2.6 million in the fourth quarter and $12.6 million for the full year, versus the comparable 2016 periods.

Other factors affecting results this year included the extended planned outage at our Morris project in the third quarter of 2016. With more typical operations this year, its Project Adjusted EBITDA increased $4.0 million. Orlando had a $4.6 million increase in Project Adjusted EBITDA for the year due to the settlement of favorable fuel swaps. Mamquam had a $3.2 million decrease in Project Adjusted

EBITDA due to lower water flows and forced outages, and Frederickson (major maintenance outage) and Calstock (lower waste heat) also experienced modest decreases.

Slide 15: Cash Flow Results and Uses of Cash

For the year, cash provided by operating activities totaled $169.2 million, an increase of $56.9 million from $112.3 million in 2016. The $169.2 million included an $18.0 million reduction to cash flow from changes in working capital. Our 2017 estimate of cash provided by operating activities of $155 to $170 million had assumed the impact of working capital was nil, so on a comparable basis results were ahead of our estimate. Key drivers of the increase were the revised operational and contractual arrangements for three of our Ontario projects, the OEFC settlement, higher water flows at Curtis Palmer, and lower fuel costs at Orlando, partially offset by several other factors, as detailed on Slide 15.

We used operating cash flow to repay approximately $100 million of our term loan and to amortize $9.3 million of project debt. We also made $5.3 million of capital expenditures (mostly for Morris) and paid $8.7 million of preferred dividends.

For the fourth quarter, cash provided by operating activities of $31.3 million increased $10.9 million from the year-ago figure of $20.4 million. Factors positively affecting cash flow were higher revenues at Morris, the timing of receipts at Oxnard, higher water flows at Curtis Palmer, the benefit to gross margin from the enhanced dispatch contracts and the expiration of the above-market gas contract in Ontario, partially offset by a modest increase in cash interest payments (related to the termination of the Piedmont rate swap upon redemption of the debt), a gas settlement at Kenilworth in 2016 that did not recur and several other factors, as detailed on Slide 15.

During the quarter, we repaid $22.7 million of our term loan and amortized $2.3 million of project debt. We also paid preferred dividends of $2.2 million. These uses were funded from our operating cash flow.

Slide 16: Liquidity

At December 31, 2017, we had liquidity of $198.2 million, including $78.7 million of unrestricted cash, which is approximately $44 million lower than the September 30th level of $122.4 million. Approximately $50 million of the cash balance was at the parent; holding aside approximately $10 million for working capital purposes, we had about $40 million of discretionary cash at year end.

The reduction in cash from the third quarter level was primarily attributable to the redemption of Piedmont project debt in full in October, as discussed in our third quarter 2017 financial results. We used approximately $60 million of cash to redeem $54.6 million of Piedmont debt and terminate an interest rate swap related to the debt.

Also in October and as discussed on the previous conference call, 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 Slide 16, we do use it for letters of credit.

Slide 17: Debt Repayment Profile

Our progress to date in debt reduction, the refinancing of our term loan and revolver, and the one-year extension of our revolver last year have improved our debt maturity profile considerably. In January of this year, we issued a new Cdn$115 million convertible debenture (Series E) with a 6.00% coupon and a January 2025 maturity date. The conversion price is Cdn$4.20 per share. After transaction costs, we are using the net proceeds of Cdn$109.1 million (or approximately $87 million on a US$ equivalent basis) to redeem in full the Series C convertible debentures, which have a June 2019 maturity, and to partially redeem the Series D convertible debentures, which have a December 2019 maturity.

Following these redemptions, which will close in early March, there will be Cdn$24.7 million of Series D convertible debentures remaining. We can redeem these at par at or before the maturity date, or repurchase a portion of them up to a 10% limit under our normal course issuer bid, or NCIB. As a result, we will have no remaining bullet maturities in 2018, a modest amount in 2019, and none in 2020 or 2021.

One other comment with respect to the convertible financing and redemptions – in the past we have indicated that we have the ability to use our corporate revolver for up to $100 million to address the convertible debenture maturities in 2019. This potential use of our liquidity has been greatly reduced as the remaining 2019 maturity is approximately $20 million on a US$ equivalent basis.

Slide 17 is a schedule of expected debt repayment by year, including amortization, projected repayment of the term loan and bullet maturities. Of note:

- This is presented as of December 31, 2017, and thus does not reflect the convertible debenture issuance and redemptions that I just discussed. On a pro forma basis, our 2019 maturities would be approximately $87 million (US$ equivalent) lower while the amount after 2023 would be $92 million (US$ equivalent) higher.

- Most of the expected debt repayment in 2018 through 2023 – other than the remaining $20 million (US$ equivalent) of convertible debentures in 2019 – is for the term loan and amortization of project debt. In total, approximately 55% 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 18: Projected Debt Balances

Slide 18 shows the impact of continued debt repayment on our debt balances, projected through year end 2023. At year end 2017, we had debt of $889 million, including our share of debt at equity-owned projects (Chambers). In early 2018, we issued $92 million (US$ equivalent) of new convertible debentures and used the net proceeds to redeem $87 million (US$ equivalent) of debentures maturing in 2019. We expect to repay and / or amortize term loan and project debt totaling $100 million this year, which would result in a projected year end 2018 debt balance of approximately $794 million.

Most of the projected reduction in debt in 2019 through 2023 is from the continued repayment of our term loan ($450 million, including $125 million remaining at the 2023 maturity date) and amortization of project debt ($59 million). At year end 2023, our projected debt balance of $265 million would consist of the $167 million (US$ equivalent) Medium-Term Notes (with a 2036 maturity), the $92 million (US$ equivalent) Series E convertible debenture (2025), and a very modest amount of project debt.

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

Slide 19: 2018 Guidance: Project Adjusted EBITDA bridge vs. 2017 actual

We have not provided guidance for Project income or Net income because of the difficulty of making accurate forecasts and projections without unreasonable efforts with respect to certain highly variable components of these comparable GAAP metrics, including changes in the fair value of derivative instruments and foreign exchange gains or losses. These factors, which generally do not affect cash flow, are not included in Project Adjusted EBITDA.

We have initiated 2018 Project Adjusted EBITDA guidance of $170 to $185 million. This represents a reduction of approximately $111 million (based on the guidance midpoint) versus the $288.8 million we reported for 2017. The significant drivers of this reduction, as depicted on Slide 19, are as follows:

- The expiration of PPAs (or extensions on lower terms) in 2017 and 2018, specifically:

  \- **North Bay and Kapuskasing**, for which the contracts expired at year end 2017. Both were significant contributors (approximately $72 million) in 2017 due to the enhanced dispatch contracts, cost savings and OEFC settlement.

  \- **San Diego projects** (Naval Station, North Island and NTC). The projects ceased operations and the PPAs were terminated, effective in February 2018. Our 2018 guidance does not assume that we are successful in achieving site control at any of the three projects and therefore we do not expect to generate any EBITDA beyond February.

  - Williams Lake. As previously discussed, we expect a significant reduction in 2018 Project Adjusted EBITDA as the project will operate under the original contract terms for only the first three months of this year and, based on our current expectation, will generate only de minimis EBITDA thereafter.

- The other drivers of the reduction are not PPA-related:

  \- **Tunis**. We expect to incur restart expenses for Tunis in the first half of this year, which will more than offset the expected EBITDA contribution under the PPA in the second half. Tunis had $5.0 million of Project Adjusted EBITDA in 2017, mostly the result of the OEFC Settlement.

  \- **Manchief**. As Dan indicated, we have a scheduled major gas turbine outage for Manchief this spring, similar to the one we undertook in 2015. The costs will be expensed. Manchief had $13.7 million of Project Adjusted EBITDA in 2017.

- **Curtis Palmer**. Our guidance assumes a return to average water flows ($3 million reduction).

On the positive side, we expect increases at Morris, due to lower maintenance expense and higher PJM capacity prices, Frederickson, which had a maintenance outage in 2017, and several other projects.

The PPA-related impact on 2018 Project Adjusted EBITDA of $105 million is consistent with the commentary we provided on our third quarter 2017 conference call. It is worth repeating that the timing of PPA expirations is lumpy. Although as of the third quarter of 2017, we had seven PPAs expiring between year-end 2017 and September 30, 2018 (a nine-month period), representing more than $100 million of Project Adjusted EBITDA, the number of PPA expirations between now and year end 2021 (nearly four years) is four – Kenilworth in September (expected to be extended), Williams Lake in 2019 and Oxnard and Calstock in 2020, for which the combined Project Adjusted EBITDA is considerably smaller. I also would note that approximately two-thirds of our 2018 Project Adjusted EBITDA is generated by projects for which the PPAs expire after 2022.

Slide 20: Bridge of 2018 EBITDA Guidance to Cash provided by operating activities

Based on our 2018 Project Adjusted EBITDA guidance range of $170 to $185 million, we estimate 2018 cash provided by operating activities in the range of $95 to $110 million. This estimate assumes the impact of changes in working capital on cash flow is nil. We expect that cash interest payments this year will be approximately $47 million, which is $25 million lower than the 2017 level, primarily because of lower debt levels, the reduction of the spread on our term loan, and the non-recurrence of $9.4 million of interest rate swap termination costs associated with the Piedmont debt repayment incurred in 2017.

Planned uses of operating cash flow in 2018 include $90 million amortization of our term loan; $9.5 million of project debt amortization; $1.4 million of capital expenditures; and $8 million of preferred dividend payments.

One last comment with regard to the 2018 outlook, and that concerns our leverage ratio. As previously indicated, at year end 2017 we had reduced our leverage ratio to 3.3 times. Notwithstanding expected repayment of $100 million this year, we expect our year end 2018 leverage ratio to move back into the high four times range, because of the significant reduction in Project Adjusted EBITDA. However, the continued significant repayment of debt in 2019 and beyond puts us back on a path to lower leverage ratios. We expect the ratio to decline below four times by 2020.

Slide 21: Tax Update

Slide 21 provides a schedule of our net operating losses (NOLs) by their expiration dates. We have also provided some additional disclosure about the impact of recent U.S. tax legislation. We have not been a significant cash taxpayer because of our NOL position; the $4.4 million of cash taxes that we paid in 2017 are mostly related to withholding taxes associated with the payment of dividends on the preferred shares in Canada. We do not anticipate becoming a federal cash taxpayer in either the U.S. or Canada in 2018 or 2019. With regard to specific provisions of the legislation, we will save a modest amount of cash taxes with the repeal of the corporate AMT. Although we expect to lose deductibility on a portion of our interest expense in 2018 and 2019, these disallowed expenses can be carried forward and utilized in 2019 and 2020.

Before concluding, there are two other items addressed in the 10-K that I will elaborate on:

Impairment

As discussed in our 10-K, we recorded an impairment of our equity investment in Frederickson in the fourth quarter totaling $28.3 million. This was triggered by a reduction in the long-term power price forecast for the region, which reduced the cash flows expected from the project in the post-PPA period. (As an equity-owned project, Frederickson is not reviewed annually for potential impairment, but only in response to a triggering event.)

We recorded a $29.1 million impairment of our Williams Lake project as a result of the uncertain outcome of the customer's IRP process and taking into consideration the economics of the short-term extension to the contract as well as a probability-weighted evaluation of cash flows under a long-term extension.

As a result of our annual assessment of the carrying value of goodwill in the fourth quarter, we recorded a $14.7 million impairment of goodwill at Curtis Palmer, reflecting a decline in the long-term power price forecast.

Including impairments of our San Diego projects in the third quarter and of our equity investments in Chambers and Selkirk in the second quarter, total impairment expense in 2017 was $187.1 million, including $85.9 million recorded in earnings from unconsolidated affiliates. The impairments are all non-cash, do not affect cash flow and are not included in Project Adjusted EBITDA.

San Diego decommissioning cost estimate

As we discussed on our third quarter 2017 conference call, our agreements with the Navy require us to decommission the facilities within a period of time after the leases expire. As disclosed in our 2017 10-K, we had accrued $6.7 million of asset retirement obligations for the projects, based on an estimate made at the time the plants were acquired that has been accreted up over time. Based on preliminary estimates that we have received from third parties, we currently expect the cost to be approximately $1.7 million, assuming no salvage value. Accordingly, in the fourth quarter, we reversed $5 million of the reserve. However, we are still in the process of determining the scope and timing of decommissioning the projects, which could be subject to negotiation with the Navy. We would then move to solicit more formal cost proposals. Thus, our initial cost estimate could change.

On the third quarter 2017 conference call, we indicated an expectation that cash outlays associated with decommissioning would be mostly offset by cash received from salvaging the assets. Since then, we have received indications that salvage values are lower than we had expected. Thus, some, or even all, of the estimated cost could represent a net cash outlay by us.

NCIB

Lastly, I would like to provide some color on how our NCIB works, in response to questions that we have received, particularly when the stock weakened considerably in January into early February. We put a new NCIB in place at the end of December, when the previous one expired. Under this program, we are permitted to purchase up to 10% of our outstanding common shares, up to 10% of the remaining Series D convertible debentures and up to 5% of our preferred shares.

We are permitted to make purchases utilizing the NCIB when the Company is not in possession of material non-public information. In addition, we have entered into a pre-defined automatic securities purchase plan with a broker through which the broker may purchase our public securities at any time, including without limitation when the Company ordinarily would not be permitted to do so due to regulatory restrictions or self-imposed blackout periods, so long as the purchase parameters were set as prescribed by the TSX in our written agreement with our broker at a time when the Company was not in possession of material non-public information.

We have been unable to make use of the new NCIB year to date due to regulatory restrictions surrounding the offering of our Cdn$115 million debentures (Series E) and the overlap with our self-imposed blackout period.

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)
Unaudited

	Three months ended December 31,		Twelve months ended December 31,	
	2017	**2016**	**2017**	**2016**
Net loss attributable to Atlantic Power Corporation	**($41.1)**	**($6.6)**	**($98.6)**	**($122.4)**
Net income attributable to preferred share dividends of a subsidiary company	2.2	2.2	5.6	8.5
Net loss	**($38.9)**	**($4.4)**	**($93.0)**	**($113.9)**
Income tax benefit	(19.7)	(0.4)	(58.1)	(14.6)
Loss from operations before income taxes	(58.6)	(4.8)	(151.1)	(128.5)
Administration	6.0	5.0	23.6	22.6
Interest expense, net	14.7	18.1	64.2	106.0
Foreign exchange (gain) loss	(1.4)	(5.1)	16.3	13.9
Other income, net	(0.4)	-	(0.4)	(3.9)
Project (loss) income	**($39.7)**	**$13.3**	**($47.4)**	**$10.1**
Reconciliation to Project Adjusted EBITDA				
Depreciation and amortization	$27.6	$42.7	$133.2	$133.5
Interest expense, net	11.2	2.7	19.2	10.9
Change in the fair value of derivative instruments	(7.9)	(17.8)	(2.1)	(37.9)
Other income, net	(58.8)	0.1	(1.2)	(0.3)
Impairment	129.8	1.2	187.1	85.9
Project Adjusted EBITDA	**$62.2**	**$42.3**	**$288.8**	**$202.2**